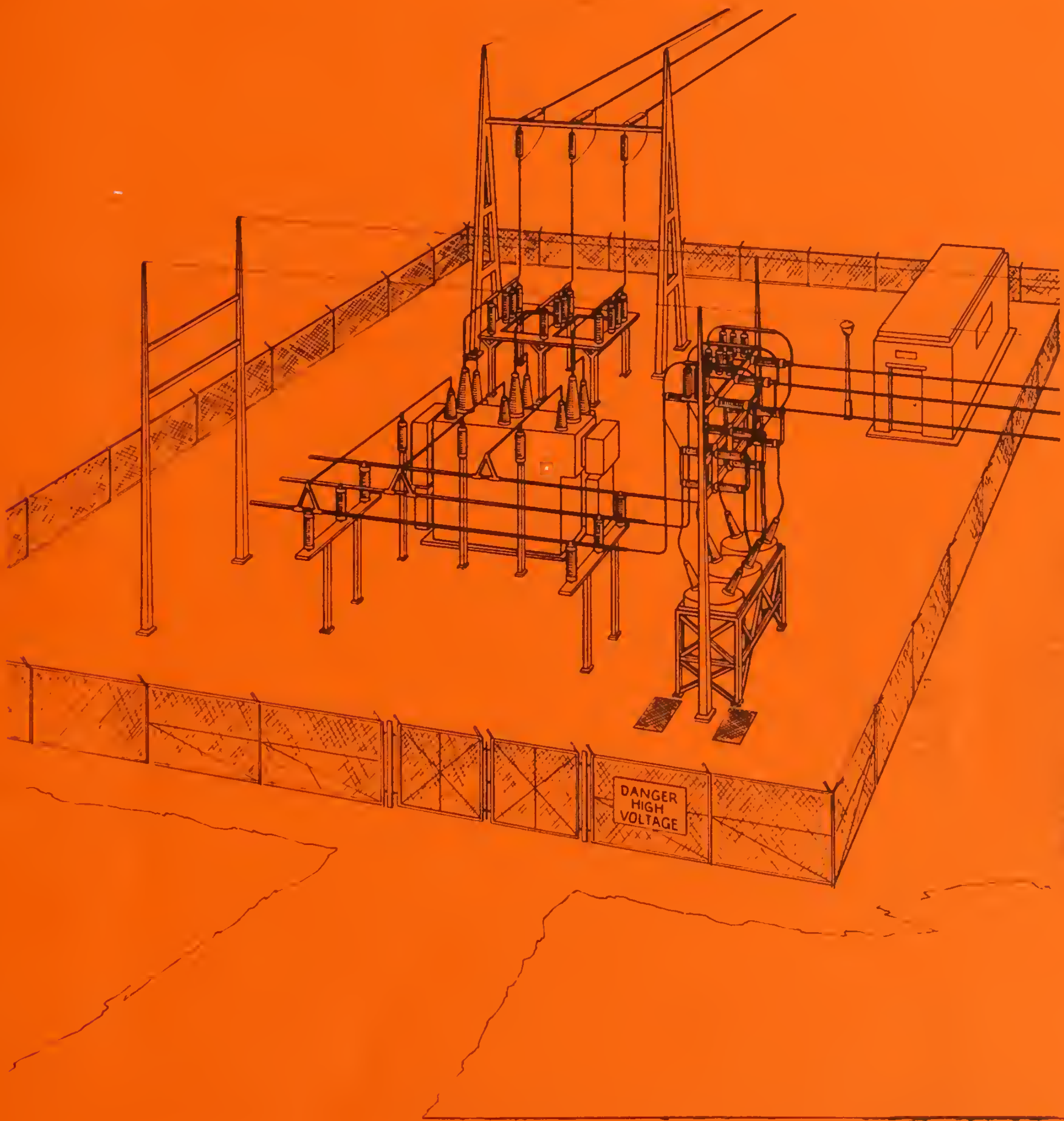
DESIGN GUIDE FOR
RURAL SUBSTATIONS



RURAL ELECTRIFICATION ADMINISTRATION • U.S. DEPARTMENT OF AGRICULTURE

REA BULLETIN 65-1

JUNE 1978

FOREWORD

This revision of REA Bulletin 65-1, "Design Guide for Rural Substations," provides engineering personnel with information covering all aspects of transmission and distribution substations through 230 kV. The only comprehensive publication of its kind in the industry specifically oriented toward rural substations, it is an excellent reference of fundamental engineering guidelines, minimum requirements and basic recommendations. The subject area includes structural, electrical, and mechanical aspects of substation construction as well as sections on layout, major equipment and maintenance.

Numerous cross references and examples, along with the latest in design technology, should be of great benefit to all engineers and engineering firms and particularly helpful to relatively inexperienced engineers beginning careers in substation design.

Assistant Administrator - Electric

Index:
- DESIGN, SYSTEM:
  - Design Guide for Rural Substations
- MATERIALS AND EQUIPMENT:
  - Design Guide for Rural Substations
- OPERATIONS AND MAINTENANCE:
  - Design Guide for Rural Substations
- SUBSTATIONS:
  - Design Guide for Rural Substations

REA BULLETIN 65-1

DESIGN GUIDE FOR RURAL SUBSTATIONS

POWER SUPPLY AND ENGINEERING STANDARDS DIVISION

RURAL ELECTRIFICATION ADMINISTRATION

U. S. DEPARTMENT OF AGRICULTURE

JUNE 1978

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CHAPTER I - INTRODUCTION

A. PREFACE

This bulletin is intended to provide design guidance for the increasing numbers of substations necessary to meet the growing electrical demands in areas served by REA Borrowers.

The substations should be designed, constructed, and operated to meet customers needs at the lowest possible cost commensurate with the quality of service desired. (See Bulletin 60-2, "Electric System Capacity.")

The typical system may include substations for voltage transformation, sectionalizing, distribution, and metering a number of times between generation and utilization.

B. PURPOSE AND SCOPE

This guide covers rural transmission and distribution air insulated, outdoor substations 230 kV (phase to phase) and below.

Most possible responsibilities of the Engineer are covered including preparation of construction drawings, material, equipment and labor specifications and any other engineering services that may be required.

The engineering function is generally more than furnishing of design and specifications. Recognition of this function becomes especially important when the REA Borrower employs an engineering firm to supplement its staff. See Bulletin 41-1, "Engineering Services for Electric Borrowers." The contract between the borrower and the engineering firm should be clear in its definition of the engineering functions to be performed. Within this bulletin, it must be understood that the term Engineer can mean either the Borrower's staff engineer(s) or the consultant's Engineer(s).

The Engineer must use these guidelines with his own experience and knowledge. A bibliography at the end of most chapters will aid in the search for more detailed information.

Use of this publication for substation design will usually result in an economical approach from a system standpoint. This should eventually result in the evolution of standard designs for a given system. Standardization is a desirable and achievable objective that should be pursued.

Technical advances and changes in codes and standards continue to proliferate in the electric power industry which could cause some of the material in this bulletin to become obsolete. Users must, therefore, continue their own efforts to keep up-to-date.

C. RELATIONSHIP OF SUBSTATION TO OVERALL POWER SYSTEM

A substation is part of a system and not an entity to itself. Normally, a power system is designed so that failure of a single component such as a transformer, transmission line, or distribution line will minimize the duration of the interruption and the number of customers affected by an interruption.

Failure of one component in a system often forces a greater than normal load to be carried by other components of the system. Such contingencies are normally planned for and incorporated into design criteria.

Most substations are designed so they will not require attendant personnel on a continuous basis. Remote indication, control, and metering and methods of communication are often provided so that systems and portions of systems can be monitored from a central point.

D. IMPORTANCE OF ADEQUATE SUBSTATION PLANNING AND ENGINEERING

(See Bulletin 60-2, "Electric System Capacity," and Bulletin 60-8, "System Planning Guide for Electric Distribution Systems.")

Substation planning considers the location, size, voltage, sources, loads and ultimate function of a substation. If the planning is not adhered to, the substation may require premature modification with the attendant unnecessary cost.

The Engineer's detail work must use valid requirements and criteria, appropriate guidelines, and his own expertise to provide construction drawings and associated documents. His ability in melding the diverse constraints into an acceptable design is essential.

During the design phase, the Engineer must not allow his intrinsic interest in solving technical problems to divert him from the use of nationally accepted standards, REA standards, or the concept of borrower's standard designs.

Adequate engineering design provides direction for construction, procurement of material, equipment, and future maintenance requirements while taking into account environmental, safety, and reliability considerations.

E. TYPES OF SUBSTATIONS

1. General

Substations may be categorized as distribution substations, transmission substations, switching substations, or any combination thereof.

Economies of scale influence substations to be as large as possible to minimize the number of them on the system. Conversely, practical system design and reliability considerations influence them to be as numerous as possible. It is a function of system studies to resolve these two viewpoints.

2. Distribution Substations

A distribution substation is a combination of switching, controlling and voltage stepdown equipment arranged to reduce subtransmission voltage to primary distribution voltage for distribution of electrical energy to residential, farm, commercial, and industrial loads.

Many rural distribution substation requirements range in capacity from one 1.5 MVA to three 5 MVA transformers and may be supplied radially, tapped from a subtransmission line, or may have two sources of supply. Most REA Borrower's substations have 12,470Y/7200 volt or 24,490Y/14,400 volt distribution circuits. Chapter IV covers the arrangements of such substations.

3. Transmission Substations

A transmission substation is a combination of switching, controlling and voltage stepdown equipment arranged to

reduce transmission voltage to subtransmission voltage for distribution of electrical energy to distribution substations. Transmission substations frequently have two or more large transformers.

Transmission substations function as bulk power distribution centers, and their importance in the system often justifies bus and switching arrangements that are much more elaborate than distribution substations.

4. Switching Substations

A switching substation is a combination of switching and controlling equipment arranged to provide circuit protection and system switching flexibility.

Switching stations are becoming common on Borrower's systems. It is anticipated that REA financed systems will develop the need for various transmission switching arrangements. Flexible switching arrangements in a transmission network can often aid in maintaining reliable service under some abnormal or maintenance conditions.

CHAPTER II - GENERAL DESIGN CONSIDERATIONS

A. INITIAL AND ULTIMATE REQUIREMENTS

Borrowers should have both short and long range plans for the development of their systems. Timely development of the plans is essential for the physical and financial integrity of the systems, as well as to supply the customers with adequate service.

The long range plan identifies the requirements of a substation not only for its initial use but also for some years in the future. Consideration should be given to ultimate requirements in the initial design and economic comparisons made to discover what provisions are necessary for ease of addition.

The Engineer must appreciate that development plans embrace philosophies of operation and protection. Departures from the plans would likely jeopardize operation of the system.

The Engineer should use the Substation Design Summary covered in the Appendix of Chapter III to summarize basic design data.

B. SITE CONSIDERATIONS

One of the most critical factors in the design of a substation is its location and siting. Failure to give careful consideration to this problem can result in excessive investment in the number of substations and associated transmission and distribution facilities.

The following factors should be evaluated in relation to the selection of a substation site:

1. Location of present and future load center

2. Location of existing and future sources of power

3. Availability of suitable right-of-way and access to site by overhead or underground transmission and distribution circuits

4. Alternate land use considerations

5. Location of existing distribution lines

6. Nearness to all-weather highway and railroad siding; accessibility to heavy equipment under all weather conditions

7. Possible objections regarding appearance, noise or electrical effects

8. Possible objections regarding present and future impact on other private or public facilities

9. Soil resistivity

10. Drainage and soil conditions

11. Cost of earth removal, earth addition, and earthmoving

12. Atmospheric conditions - salt and industrial contamination

13. Space for future as well as present use

14. Land title limitations, zoning, and ordinance restrictions

15. General topographical features of site and immediately contiguous area. Avoidance of earthquake fault lines, flood plains, wetlands, and prime or unique farmlands where possible

16. Public safety

17. Security from theft, vandalism, damage, sabotage and vagaries of weather

18. Total cost including transmission and distribution lines with due consideration of environmental factors

19. Consideration of impact on rare and endangered species

C. ENVIRONMENTAL CONSIDERATIONS

1. General

REA Bulletin 20-21, "National Environmental Policy Act," calls for the implementation of the National Environmental Policy Act of 1969 as it relates to the REA program. Bulletin 20-21 also references additional authority,

directives, and instructions relevant to protection of the environment.

As a general rule, stations 230 kV and above need Environmental Statements, while those below generally require a brief environmental report.

Attention is also called to the publication jointly issued by the Secretary of Agriculture and the Secretary of the Interior entitled "Environmental Criteria for Electric Transmission Systems." These criteria are recommended for designing, constructing, and operating transmission systems. Copies of "Environmental Criteria for Electric Transmission Systems" are available from the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402.

2. <u>Appearance</u>

Appearance is becoming increasingly important to the public. In some areas, zoning regulations and suggestions by civic organizations often require screening, low profile designs, or other measures to improve appearance. The absence of such direct influence in rural areas should not be a reason for not considering newer design practices. The general trend is away from locating substations in a way that they are strikingly visible to the public. A substation set back from a heavily traveled road may require little or no architectural treatment to be acceptable.

The silhouette of a substation may be reduced in several ways including the use of solid-shape structural sections.

Engineering of transmission, distribution and substation facilities should be coordinated to develop the least overall objectional layout. Underground distribution circuit exits should be considered for special applications.

Lowering of substation profile may also be accomplished by means other than underground circuits although this approach may necessitate a larger ground area.

Landscaping or architectural screening may be appropriate to effectively blend a substation into the surrounding environment.

Generally, it is better to use complementary rather than contrasting colors. Sometimes, coloring can be used to blend the substation equipment into the background.

3. Public Safety

Substations should be safe for people who may have occasion to be near them.

The primary means of ensuring public safety at substations is by the erection of a suitable barrier such as a metal fence. Unless local restrictions are more conservative, the fence shall meet the minimum requirements specified in the National Electric Safety Code, Paragraph 1 (also may be identified as American National Standard C2.1 and National Bureau of Standards Handbook 110-1). Grounding of fences is further covered in Chapter IX; material and specification of fences is further covered in Chapter VI.

Additional means of protecting the public are through adequate design of all facilities inside the fence and the addition of a peripheral ground outside the fence. Protection against possible potential differences is discussed in Chapter IX.

Appropriate warning signs should be posted on the substation's peripheral barrier. The Engineer should specify their location and design. Substations no matter how small should have one sign per side minimum.

4. Audible Noise

Sources of audible noise within a substation include transformers, voltage regulators, circuit breakers and other intermittent noise generators.

Corona, which is localized incomplete dielectric failure, causes a hissing sound. The amount of this noise occurring at voltages of 230 kV and below is seldom serious. It is usually kept to a tolerable level if the same guidelines are followed as those for minimizing electrical effects; see Reference 5, "Electrostatic and Electromagnetic Effects."

Among the sources, transformers have the greatest potential for producing objectionable noise. The United States Environmental Protection Agency (EPA) has prepared a document "Information on Levels of Environmental Noise Requisite to Protect Public Health and Welfare With An Adequate Margin of Safety," (Report Number 550/9-74-004). The EPA has also published "Public Health and Welfare Criteria For Noise," (Report Number 550/9-73-002). There are several state and local noise ordinances known to exist, some of which contain

regulations limiting noise at the property line. The reaction to noise can be subjective, so each substation situation should be analyzed.

To minimize the possibility of acoustical problems, the Engineer should consider the following:

a. Site Selection - If the substation must be located in or near a residential area, select a site the greatest distance from nearby residences, and, if possible, avoid a direct line of sight with them. A site with natural barriers such as mounds or shrubbery is desirable, since this can help reduce the psychological impact of a new installation.

b. Layout Design - Good practice for noise control is to locate a transformer the maximum distance from a fence. Once the transformer is located, its noise level at any distance can be determined by using a standard formula; See "Standard Handbook for Electrical Engineers" published by McGraw-Hill. If noise is anticipated to be a problem, the equipment layout should be arranged to permit the installation of a sound barrier. Anticipated future requirements should also be considered, since additional transformers will increase the noise level.

c. Level - As a general rule, substation noise will not be a problem if, when combined with the ambient noise, it is less than 5 dBA above the ambient noise level. It may be desirable to measure the ambient noise levels at locations of concern. Measurements should be taken during the quietest periods, approximately midnight to 4 a.m. Calculation of resultant sound level will then indicate whether further study is required. The references in this chapter's bibliography suggest methods to rigorously address noise problems.

d. Transformers - Chapter V, "Major Equipment," Section A "Power Transformers" provides additional guidelines.

5. Electrostatic and Electromagnetic Effects

Consideration should be given to preventing radio and television interference that could result if there is visible corona. Significant corona could be caused by energized parts having small radii or from small diameter

conductors, particularly when conducive climatic conditions prevail. Experience has shown, though, that conductor fittings and energized parts other than conductors do not produce serious corona at phase to phase voltages of 230 kV and below.

It is necessary, however, to give some consideration to the size of conductors. Chapter IV gives guidelines for fault and load carrying conductors. Connections to equipment such as voltage transformers and coupling capacitors should not be sized from a current carrying standpoint only. They should, from a corona standpoint, be not smaller than 3/0 at 230 kV or 1/0 at 161 and 138 kV.

6. Effluent

The Environmental Protection Agency has promulgated regulations to eliminate the pollution of navigable waterways. The essence of these regulations is that in the event of the failure of containment of a pollutant, such as transformer or circuit breaker oil, no significant quantity of such pollutant may be allowed to enter a navigable waterway. No absolute prevention is required if such pollution is not reasonably expected. However, it is necessary to have a plan of action for disposing of effluent should spills or leaks occur. Some oil pollution prevention measures are described in Chapter VIII.

Until very recently, askarel was used in almost all capacitors. This type of impregnant is being phased out, due to its resistance to biodegradation, in favor of materials potentially less harmful to the environment. ANSI Standard C107.1, "Guidelines for Handling and Disposal of Capacitor and Transformer-Grade Askarels Containing Polychlorinated Biphenyls" gives a comprehensive review of the subject.

D. NATURE CONSIDERATIONS

1. Weather

a. General - As dependence on the use of electricity grows, it is increasingly important that substations operate more reliably in extremes of weather than in the past.

b. Temperature - It is necessary to design a substation for the extreme temperatures expected.

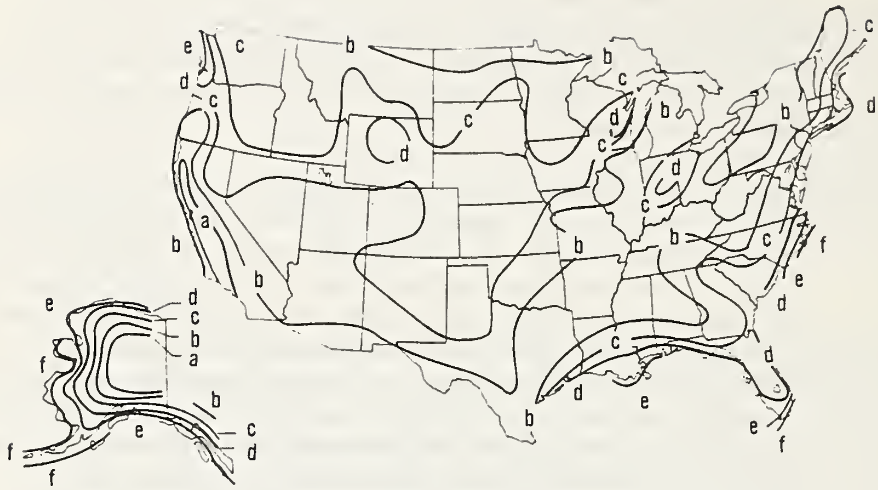
c. Wind - As a minimum, substations should be resistant to wind velocities as shown in Figure II-1. (This is a modified reproduction of Figure 1 and part of Table 4 of ANSI Std. A58.1 "Building Code Requirements for Minimum Design Loads in Buildings and Other Structures.") Chapter IV, "Physical Layout," and Chapter VII, "Structures," give specific guidelines on design. Local conditions may dictate more stringent wind designs.

d. Ice - A substation must continue to operate despite ice accumulation. Generally, the consensus equipment standards specify ice loadings to be withstood for both electrical and mechanical factors. The complete substation assembly must also be undamaged by ice accumulation. From ice accumulation history for a given substation's location, the Engineer can judge whether or not more severe loadings than consensus equipment standards are necessary. Additional viewpoints on ice loading are given in Chapter IV, "Physical Layout," and Chapter VII, "Structures."

e. Rain - A substation should be designed to be operable under predictable conditions of rainfall. Additionally, it is desirable that a substation be so drainable as to exhibit little standing water within a few hours after a heavy rainfall. See Chapter VI, "Site Design," for guidelines.

f. Snow - Snow introduces an extremely variable hazard to substations because of uncertainties in drifting and accumulation. The substation must be impervious to snow damage, and consideration must be given to snow accumulation and the maintenance of clearances. The Engineer should seek local data on this weather variable.

g. Electrical Storms - The two measures normally employed for lightning protection are surge arresters and shielding. Application guidelines for surge arresters are given in Chapters IV and V. Surge arresters provide very little protection against direct strokes. Shielding is provided by overhead wires, masts which are extensions of structures, or independent masts as covered in Chapter IV. A combination of surge arresters and shielding will reduce the probability of damage from lightning.



	KM/HR	MPH
(a)	96.5	(60)
(b)	112.6	(70)
(c)	128.7	(80)
(d)	144.8	(90)
(e)	161.0	(100)
(f)	177.0	(110)

HAWAII 128.7 (80)

FIGURE II-1

Basic Wind Speed in Kilometers per Hour (Miles per Hour)
Annual Extreme Fastest-Mile Speed 9.144 Meters (30 Feet)
Above Ground, 50-Year Mean Recurrence Interval

h. Humidity - Consideration should be given to installation of differential thermostat controlled heating in outdoor cabinets such as circuit breaker control cabinets where condensation could be a problem. In areas where fog occurs often and particularly where airborne contamination exists, frequent insulator flashovers may occur. Methods of reducing flashovers include the application of special insulation and insulator cleaning.

2. Altitude

Equipment that depends on air for its insulating and cooling medium will have a higher temperature rise and a lower dielectric strength when operated at higher altitudes; see ANSI Standard C37.3, "Definitions and Requirements for High-Voltage Air Switches, Insulators, and Bus Supports."

Surge arresters are designed for satisfactory operation at elevations up to a limit specified by the manufacturer. Applications above this limit are considered special and the manufacturer should be consulted for his recommendation.

Dielectric strength of air and current ratings of conductors operated in air should be multiplied by factors shown in Columns "A" and "B" of Table II-1.

3. Earthquakes

No substation subjected to intense earthquakes could be expected to escape undamaged. Therefore, earthquake damage must be considered in certain areas.

TABLE II-1
ALTITUDE CORRECTION FACTORS
FOR SUBSTATION EQUIPMENT

Altitude		Altitude Correction Factor to be Applied to:		
		A	B	C
Meters	Feet	Dielectric Strength	Current Rating	Ambient Temperatures
1000	3300	1.00	1.00	1.00
1200	4000	0.98	0.995	0.992
1500	5000	0.95	0.99	0.980
1800	6000	0.92	0.985	0.968
2100	7000	0.89	0.98	0.956
2400	8000	0.86	0.97	0.944
2700	9000	0.83	0.965	0.932
3000	10000	0.80	0.96	0.920
3600	12000	0.75	0.95	0.896
4200	14000	0.70	0.935	0.872

Much substation equipment is inherently shock resistant. The assembly of the total substation - foundations, structures, equipment, insulation and conductors - may not be. Designs to minimize damage probability should be followed in Seismic Risk Zones 2 and 3, Reference Figures II-2, II-3 and II-4. Application of the guidelines given in succeeding Chapters will minimize the probability of damage to substations from seismic forces.

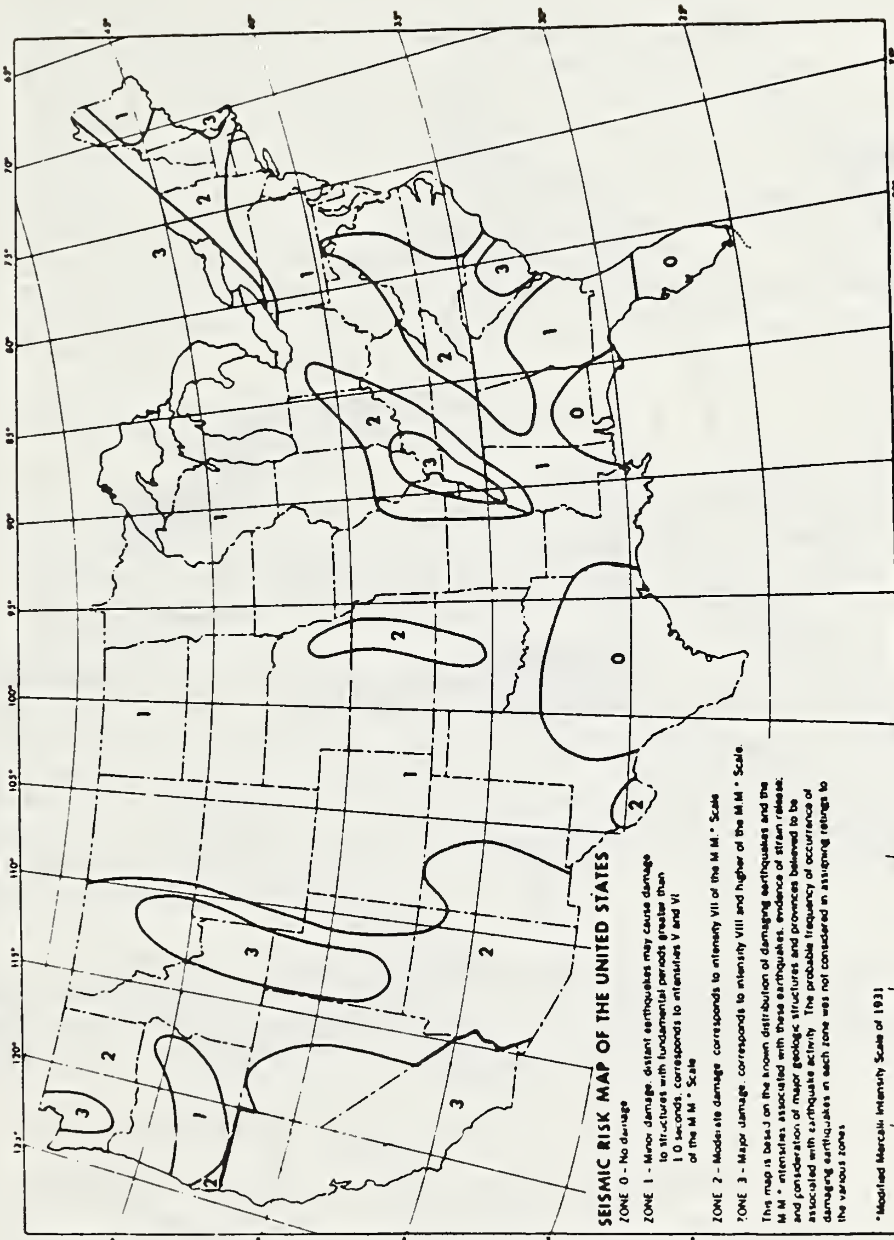


FIGURE II-2 SEISMIC ZONE MAP OF THE UNITED STATES

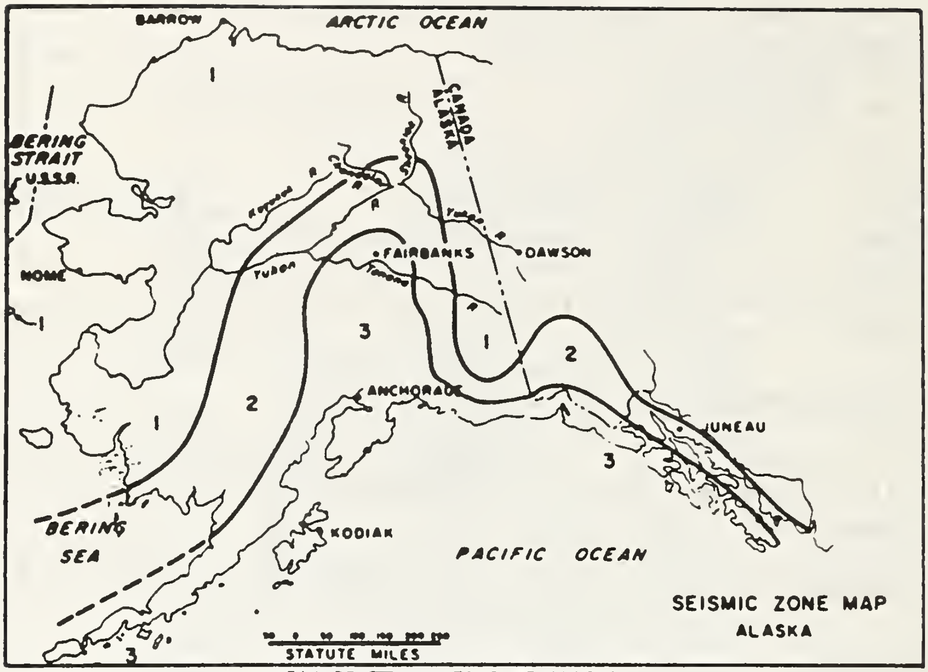


FIGURE II-3 STATE OF ALASKA

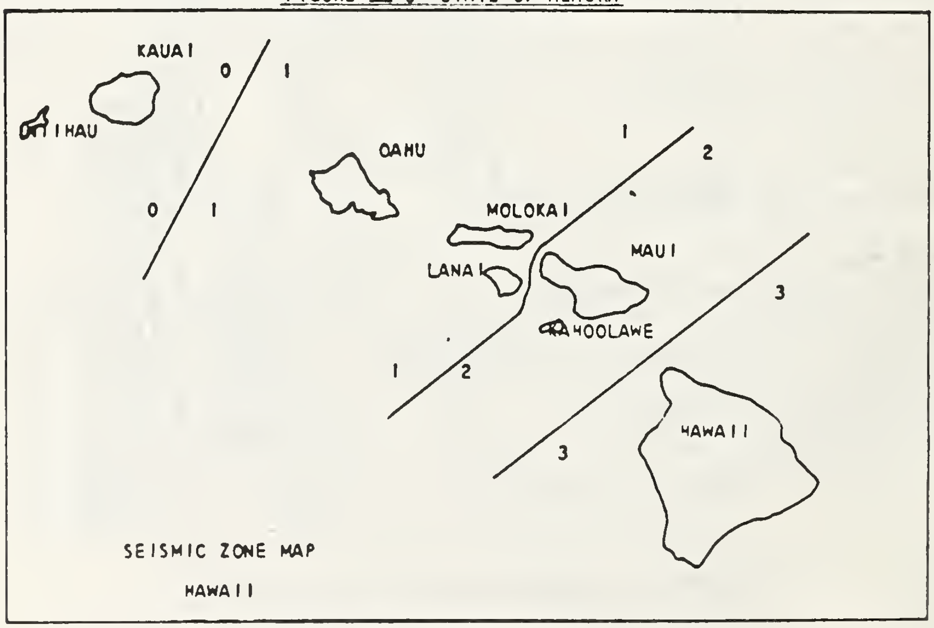


FIGURE II-4 STATE OF HAWAII

4. Wildlife & Livestock

A substation should be protected from wildlife and livestock. The primary means is the perimeter barrier. This is generally a chain link fence that keeps out larger animals. It may also be necessary to have rodent and/or reptile barriers. It is recommended that all substation materials be nonnutrients, since impregnable barriers would be too costly. Insect screening should be applied where local experience indicates. Bird damage is usually minimized by avoiding attractive nesting and perching sites. Keeping clearances adequate for local bird species should be kept in mind because possible perching spots usually cannot be eliminated.

5. Air-Borne Foreign Material

Air-borne seeds, leaves, debris, dust and salts that are local phenomena could be a problem. Build-up could occur that would compromise electrical insulation or would interfere with cooling. Recognition to such conditions should be given in the design of a substation.

E. INTERFACING

A substation will interface with a vehicle roadway, area drainage, communication system and electric power lines. Sufficient lead time must be allowed to coordinate activities with both public agencies for roadway access and with communications agencies for communications facilities. Chapter XVI provides details on communications considerations.

There should be no difficulty in ensuring proper interfacing with distribution, subtransmission, and transmission lines. Timely plans should be made so there is mutual agreement between the substation engineer and the lines engineer on the following:

1. Connecting hardware procurement responsibility
2. Mating of hardware to line support structure
3. Line identifications and electrical connections to suit planning engineering requirements
4. Substation orientation and line approach
5. Phase conductor and shield wire identification

6. Pull-off elevations, spacings, tensions and angles. Confusion sometimes occurs in the matter of specifying tensions. In some cases, line tensions on the line side of a line approach or dead end structure will be much greater than on the line support structure in the substation. The tension specified to the substation engineer should be the tension that will be a maximum on the substation line support structure for the wire under the most severe combination of temperature, wind and ice loading. The condition at which maximum tension occurs must be known in order to select overload factors. Chapter VII, "Structures," covers overload factor selection.

As a general rule, takeoff tensions should not exceed 8900 newtons (2000 pounds) per conductor for small distribution substations.

F. RELIABILITY

A prime objective in the operation of an electric power system is to provide reliable service within acceptable voltage limits. Bulletin 60-7, "Service Reliability," provides information on reliability. Borrowers following criteria in this guide should have reasonably reliable substations.

G. OPERATING CONSIDERATIONS

For simplicity and ease of maintenance, substation equipment arrangements, electrical connections, signs and nameplates should be as straightforward as possible. Novel situations are to be avoided lest they contribute to the possibility of operating errors.

A substation may occasionally experience emergency operating conditions. Depending on the length of time, the provision of unusual current carrying capacity of some equipment or connections may have to be considered in the design.

H. SAFETY CONSIDERATIONS

It is paramount that substations be safe for the Borrower's operating and maintenance personnel. Practical approaches include the employment and training of qualified personnel, appropriate working rules and procedures, proper design and correct construction. Safeguarding of equipment must also be a consideration in substation design.

Minimum personnel working standards are prescribed by regulations issued by the Occupational Safety and Health Administration (OSHA). The basic documents have been published in Title 29, Code of Federal Regulations Part 1910 for General Industry and Part 1926 for Construction. In addition, various states may have standards the same as or stricter than those of OSHA. The Engineer is expected to follow the regulations appropriate to the jurisdiction in which a substation is built.

It should be recognized that this Bulletin presents minimum guidelines. The Engineer has the responsibility for compliance with the applicable requirements of REA, the National Electric Safety Code, National Electric Code, OSHA and local regulations.

I. MAINTENANCE CONSIDERATIONS

Thought must be given in design to allow maintenance with a minimum impact on a substation's function. Allocation of adequate working space will make maintenance more convenient.

Selection of durable equipment will minimize the need for maintenance. Since it is to the vendor's advantage to offer equipment with minimal maintenance requirements, it is desirable that the Engineer keep aware of such improvements in available products.

REFERENCES

1. U.S. Environmental Protection Agency, Information On Levels Of Environmental Noise Requisite To Protect Public Health And Welfare With An Adequate Margin Of Safety, Report Number 550/9-74-004, Washington, D.C., March, 1974.

2. C. R. Bragdon, "Municipal Noise Ordinances: 1975", Sound and Vibration, December, 1975, Volume 9, Number 12, pp. 24-30.

3. U.S. Environmental Protection Agency, Public Health And Welfare Criteria For Noise, Report Number 550/9-73-002, Washington, D.C., July 27, 1973.

4. Fink and Carroll, Standard Handbook For Electrical Engineers, 10th Edition, 1968, McGraw-Hill, Section 11-100.

5. R. S. Pedersen, Audible Noise Reduction In New And Existing Substations, Engineering and Operating Conference, Pacific Coast Electrical Association, San Francisco, California, March 18-19, 1976.

6. M. W. Schulz, Transformer Audible Noise, IEEE Power Engineering Society Summer Meeting, Portland, Oregon, July 17-23, 1976.

7. E. B. Lawless, III, Noise Control Regulations And Effects Upon Substation Design, Annual Conference of Engineering and Operation Division, Southeastern Electric Exchange, New Orleans, Louisiana, April 26-27, 1976.

CHAPTER III - DOCUMENTS

A. GENERAL

The primary function of a substation design Engineer is to produce or supervise the development of formal plans from which a substation can be constructed.

Following is a list of documents or studies that may also be required as part of the Engineer's responsibility. The timing and chronological order of the documents may vary, depending upon the particular substation's requirements.

1. Site Comparison and Suitability Evaluation
2. Environmental Impact Statement (input) or Brief Environmental Report
3. Substation Design Summary Form
4. Functional One Line Diagram
5. Application for zoning variance or change
6. Specifications for Equipment
7. Request for Proposals to Furnish Equipment
8. Evaluation of Proposals to Furnish Equipment
9. Construction Plan Drawings
10. Backup Sketches and Calculations for Construction Plans
11. Substation Drawings not Actually Used for Construction (Detailed one line, elementary, and schematic diagrams)
12. Requisitions for Material and Equipment
13. Application for Building Permit
14. Application for Permits for Roadway and Drainage Interface

15. Application for FCC License

16. Construction Specifications

17. Inquiry for Proposals to Furnish Construction

18. Evaluation of Contractor's Proposals

19. Comment Letters on Equipment Vendors' Submittals

20. Calculations for Selection of Protective Relaying and Devices

21. Economic Comparisons

During the formulation of design, some sketching and calculations are required in order to arrive at optimum designs. While these are not a part of the formal plans, they are nevertheless useful in planning and are often valuable for future reference.

All documentation shall be done in metric units with English units as a parenthetical reference. For example, a dimension on a drawing might be 1.98 m. (6'-6").

B. NEED FOR DOCUMENTATION

Documentation establishes a basis by which the Engineer expresses and evaluates his own ideas. A document serves as a vehicle for the Borrower and Engineer to reach agreement on a subject. In its final form, a document fulfills its primary role of establishing design and functional requirements. A document also serves as a record of what was built, specified, or evaluated. The importance of good records in substation design deserves emphasis. Successful designs and accurate records are convenient references for designs and for standardized approaches for new substations. Records can also be very useful in diagnosing and correcting problems.

C. PROCEDURES

REA has procedures that must be followed and, in addition, each Borrower may have certain procedures that suit his needs.

The chronology of a substation is generally as shown below -- elapsed times varying according to a particular project's requirements. It is desirable to bear in mind consultation with the REA field representative. See Bulletin 40-6, "Construction Methods and Purchase of Materials and Equipment," and

Bulletin 81-9, "Preparation of Plans and Specifications for Distribution and Transmission Facilities."

Substation Design Chronology

1. Identification of substation need from power supply study or Borrower's long range plan

2. Pre-loan engineering

3. Application for Loan; See Bulletin 20-2, "Loan Processing for Distribution Borrowers"

4. Loan approval

5. Final procurement of real estate

6. Selection of major equipment

7. Preparation of plans and specifications; See Bulletin 81-9, "Preparation of Plans and Specifications for Distribution and Transmission Facilities"

8. REA Form 764, "Substation and Switching Station Erection Contract." This will generally be required for systems with limited construction forces.

9. Approval of plans and specifications by Borrower's board of directors; see Bulletin 40-6, "Construction Methods and Purchase of Materials and Equipment"

10. Design approval by REA as required

11. Selection of a construction contractor
When competitive bids are to be taken for substation construction, the Engineer's role is that described in Bulletin 40-6. Also, see REA Form 764, "Substation and Switching Station Erection Contract"

12. Construction

13. Inspection; see REA Form 235, "Engineering Service Contract Electric Substation Design and Construction," and Bulletin 81-6, "Close-Out Procedures and Documents for Contract Construction of Distribution and Transmission Facilities"

14. Testing

15. Energizing

D. PROCUREMENT

The methods and documentation for obtaining substation equipment are as follows:

1. Purchase order following informal quotations, or

2. Contract and purchase order following formal competitive bidding

Guidelines and procedures applicable to the selection of materials and equipment include the following REA Bulletins:

Bulletin 40-1, "Specifications and Standards for Materials and Equipment"

Bulletin 40-6, "Construction Methods and Purchase of Materials and Equipment"

Bulletin 43-5, "List of Materials Acceptable for Use on Systems of REA Electrification Borrowers"

Bulletin 43-6, "Selection and Inspection of Materials and Equipment"

Bulletin 43-9, "'Buy American' Requirement"

Bulletin 44-7, "Acceptance of Standards, Standards Specifications, Drawings, Materials and Equipment for the Electric and Telephone Programs"

The size and complexity of a project can greatly influence the choices in procurement. Lead times for procurement of major and/or special equipment in many cases may favor incremental purchases of equipment.

Smaller projects may lend themselves more to "standard package" type procurement while the procurement for larger projects may require many vendors.

E. DRAWINGS

1. General

The smaller and less complex substations naturally do not need as many different types of drawings as the larger more complicated substations.

For a basic distribution substation, the "One Line Diagram" and "Plot Plan" may be the drawings that need to be custom made by the Engineer. For example, if a substation is small, it may be possible to show foundation details on the "Plot Plan" drawing. In a similar manner, the grounding layout and details might be shown on a "Plot Plan."

Larger substations will, of necessity, require more extensive documentation. REA Form 235, "Engineering Services Contract - Electric Substation Design and Construction," gives a basic list of drawings often necessary.

2. Quality

a. REA Bulletin 60-1

Substation drawings of any kind should conform to the requirements of Bulletin 60-1, "Circuit Diagrams, Electrical Data Sheets and Other Drawings for Systems of Electric Borrowers." The drawing material, "tracing linen or paper," as applicable, is interpreted as a durable, commercially available material satisfactory for making reproducible pencil drawings.

b. Drafting Practice

It is recommended that drafting practices be in accordance with "American Drafting Standards Manual," ANSI Y14. Prints of the drawings will be used in construction, not always under the most convenient conditions. Equipment outlines are preferred to detailed pictorial repre-sentations. Pertinent component interfaces and connec-tions should be illustrated in adequate detail for construction and record purposes. Pertinent distances must be dimensioned. Drawings, though made to scale, should not have to be scaled for construction purposes. Thought should be given to choosing scales and lettering sizes appropriate for the type of drawing. It would be desirable to use bar type graphic scales on

all drawings, since many of them may be reproduced to different sizes. Plans, elevations, and sections should be organized for maximum clarity. Tolerances should be noted on drawings such as those that specify foundation anchor bolt locations and equipment mounting holes on control panels. Simplicity and clarity of drawings are essential.

c. Legends, Notes, Symbols

A definitive legend should be on the first sheet of each type of drawing. This legend should not only include the standard symbols, but all special symbols or designations. A set of notes is often found to be a desirable supplement on a drawing. The guideline here is that judgment must be exercised to avoid overdoing notation. It may be better to consider additional details on the drawings rather than a long list of notes. Electrical symbols should be in accordance with "Graphic Symbols for Electrical and Electronics Diagrams," ANSI Y14.15.

d. Reference Drawings

Proper care must be given to the listing of reference drawings to ensure a coherent, concise pattern.

e. Titles

Drawing titles should be concise, accurate, and specific. They should not be so general that the drawing itself must be viewed to see what it covers.

f. Approvals

Every drawing or revision to a drawing should indicate the proper approvals and dates.

3. Types of Drawings

Following are the main types of substation construction and reference drawings often required. The appendix to this chapter has check lists covering some types of drawings. It is recommended that the Engineer use checklists as a design quality control tool.

a. One Line Diagram - Switching

b. One Line Diagram - Functional Relaying

The one line diagrams are the major substation reference drawings and require special emphasis. These should be the first drawings prepared. The switching and functional relaying information may appear on the same one line diagram if the presentation is not too complicated. It is recommended that One Line Diagrams be prepared as follows:

(1) Use acceptable symbols. Identify all symbols in the legend.

(2) Arrange equipment symbols geographically correct, as much as practical, with respect to each other.

(3) Put a north arrow on the drawing to orient the diagram the same as the Electrical Plot Plan.

(4) Apply an appropriate numbering scheme for major equipment.

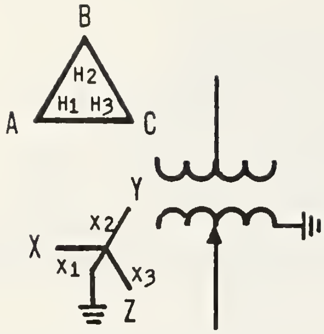
(5) Identify buses and line connections.

(6) Lines representing power carrying conductors should be heavier than those representing connections to voltage transformers, to current transformer secondary windings, etc.

(7) Vector relations and phasing should be specified, where appropriate.

(8) Acceptable symbols for some of the most common substation equipment are illustrated below in Figures III-1 through III-18. Generally, these symbols are based upon ANSI Y14.15. Drafting templates are commercially available to assist in developing the one line diagrams. Each symbol should be accompanied by the pertinent equipment information indicated.

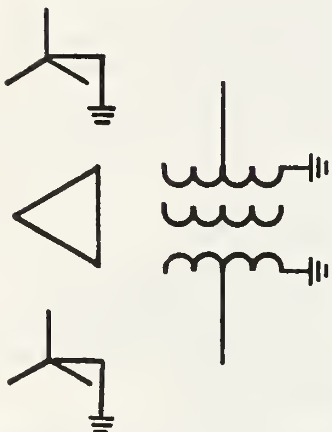
Figures III-19, III-20, and III-21 give elementary examples of symbols in combination. Figure III-19 shows a conceptual One Line Diagram of a transmission substation. This is merely to illustrate use of some



MANUFACTURER	
TYPE	OA/FA/FOA ETC. AS APPLICABLE
CAPACITY	(__/__/__ MVA)
VOLTAGE	(__/__/__/ETC __/__-__KV)
IMPEDANCE	(__ OHMS HV-LV)
	(SHOW PHASING AND TERMINAL DESIGNATION ON VECTORS)

FIGURE III-1 POWER TRANSFORMER

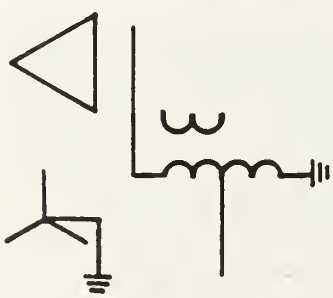
(SHOWN WITH LOAD TAP CHANGER ON LOW VOLTAGE SIDE)



INFORMATION SAME AS FIGURE 1 ABOVE EXCEPT INCLUDE ALL IMPEDANCES

(HV-LV __ % ON __ MVA BASE)
(HV-TV __ % ON __ MVA BASE)
(LV-TV __ % ON __ MVA BASE)

FIGURE III-2 THREE PHASE TRANSFORMER WITH TERTIARY

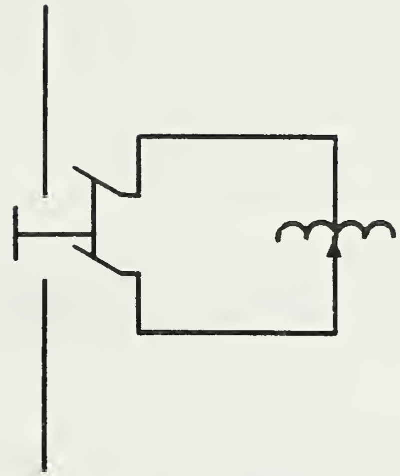


INFORMATION SIMILAR TO FIGURE 1 ABOVE

FIGURE III-3 THREE PHASE AUTO-TRANSFORMER

NO. – MFR – TYPE

__ A   __ KV



MFR – TYPE

__ Φ

__ KVA __ A

__ KV __ %

__ KV BIL

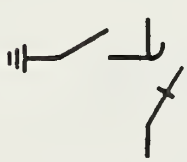
FIGURE III-4 STEP VOLTAGE REGULATOR WITH BYPASS SWITCH

3 – MFR – TYPE

__ A   __ KV

__ KV BIL

FIGURE III-5 HOOK STICK OPERATED DISCONNECTING SWITCH



MFR – TYPE

__ A   __ KV

__ KV BIL

FIGURE III-6 THREE PHASE GANG OPERATED DISCONNECTING SWITCH WITH HORN GAPS AND GROUNDING SWITCH

MFR – TYPE

__ A   __ KV

__ KV BIL

FIGURE III-7 THREE PHASE DOUBLE SIDE BREAK DISCONNECTING SWITCH WITH MOTOR OPERATOR

1 OR 3 – MFR – TYPE

__ A   __ KV

__ A LINK (OR MFR CAT. NO.)

__ KV BIL

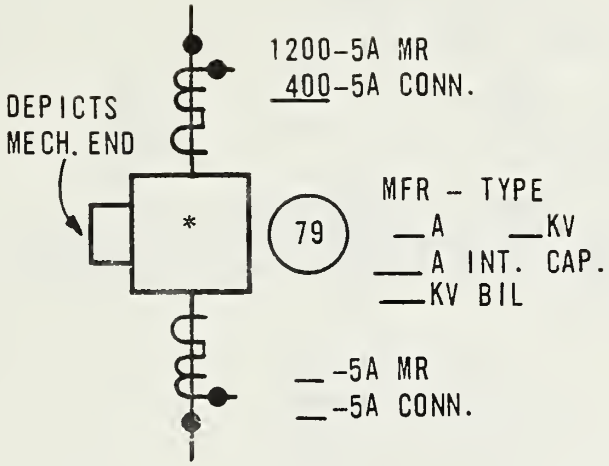
FIGURE III-8 FUSED DISCONNECT

1 OR 3 – MFR – TYPE – 1 OR 3Φ

__ A   __ KV

__ KV BIL

FIGURE III-9 OIL CIRCUIT RECLOSER



*
INTERRUPTING MEDIUM

A FOR AIR
O FOR OIL
V FOR VACUUM
G FOR GAS

FIGURE III-10 CIRCUIT BREAKER

(SHOWN WITH BUSHING TYPE CT'S AND RECLOSING RELAY)
(SHOW POLARITY MARKS IF ONE LINE FUNCTIONAL RELAYING DIAGRAM)

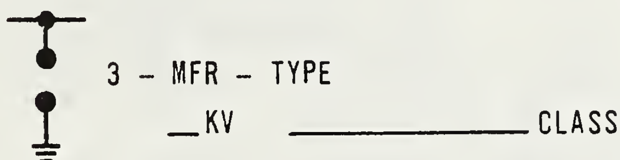


FIGURE III-11 SURGE ARRESTER

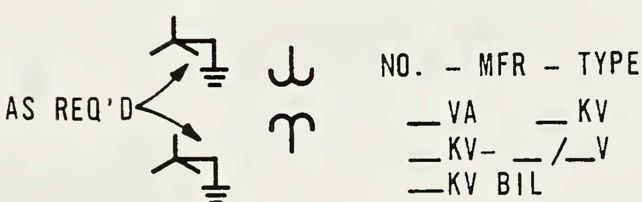


FIGURE III-12 VOLTAGE TRANSFORMER

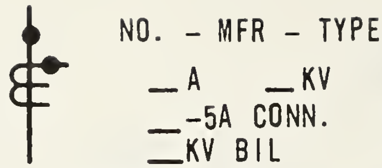


FIGURE III-13 CURRENT TRANSFORMER

(SHOW POLARITY MARKS ON FUNCTIONAL RELAYING ONE LINE DIAGRAM)

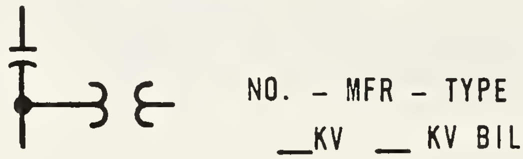


FIGURE III-14 COUPLING CAPACITOR WITH VOLTAGE TRANSFORMER

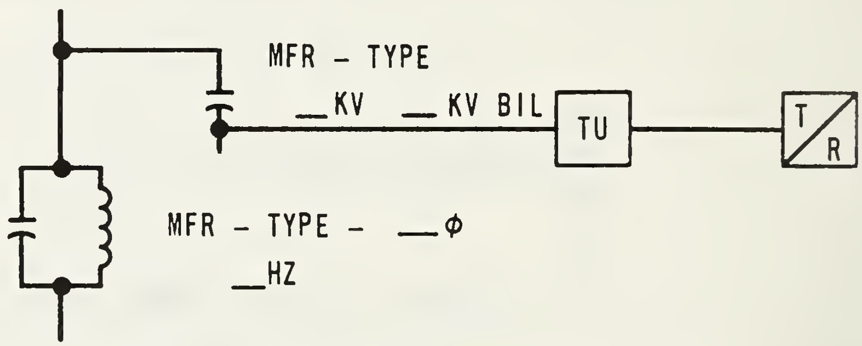


FIGURE III-15 COUPLING CAPACITOR, WAVE TRAP TUNING UNIT AND POWER LINE CARRIER TRANSMITTER/RECEIVER

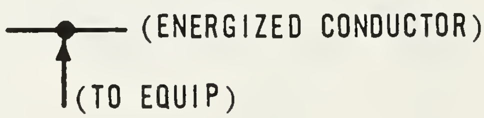
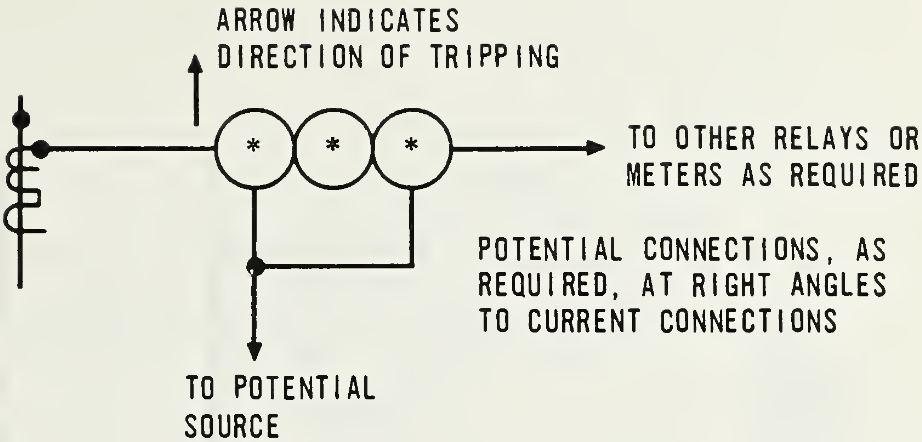


FIGURE III-16
DISCONNECTING CLAMP

FIGURE III-17
SHUNT CAPACITOR



* A PARTIAL LISTING OF DEVICES AS FOLLOWS:

A (FOR AMMETER)
V (FOR VOLTMETER)
W (FOR WATTMETER)
WH (FOR WATT-HOUR METER)
VAR (FOR VOLT AMPERE REACTIVE METER)

OR A NUMBER IN ACCORDANCE WITH ANSI STD. C37.5
SUCH AS THE FOLLOWING COMMONLY USED NUMBERS:

21 (DISTANCE RELAY)
27 (UNDERVOLTAGE RELAY)
32 (DIRECTIONAL POWER RELAY)
50 (INSTANTANEOUS OVERCURRENT RELAY)
51 (AC TIME OVERCURRENT RELAY)
67 (AC DIRECTIONAL OVERCURRENT RELAY)
74 (ALARM RELAY)
87 (DIFFERENTIAL PROTECTIVE RELAY)

FIGURE III-18 TYPICAL RELAY AND METER REPRESENTATION

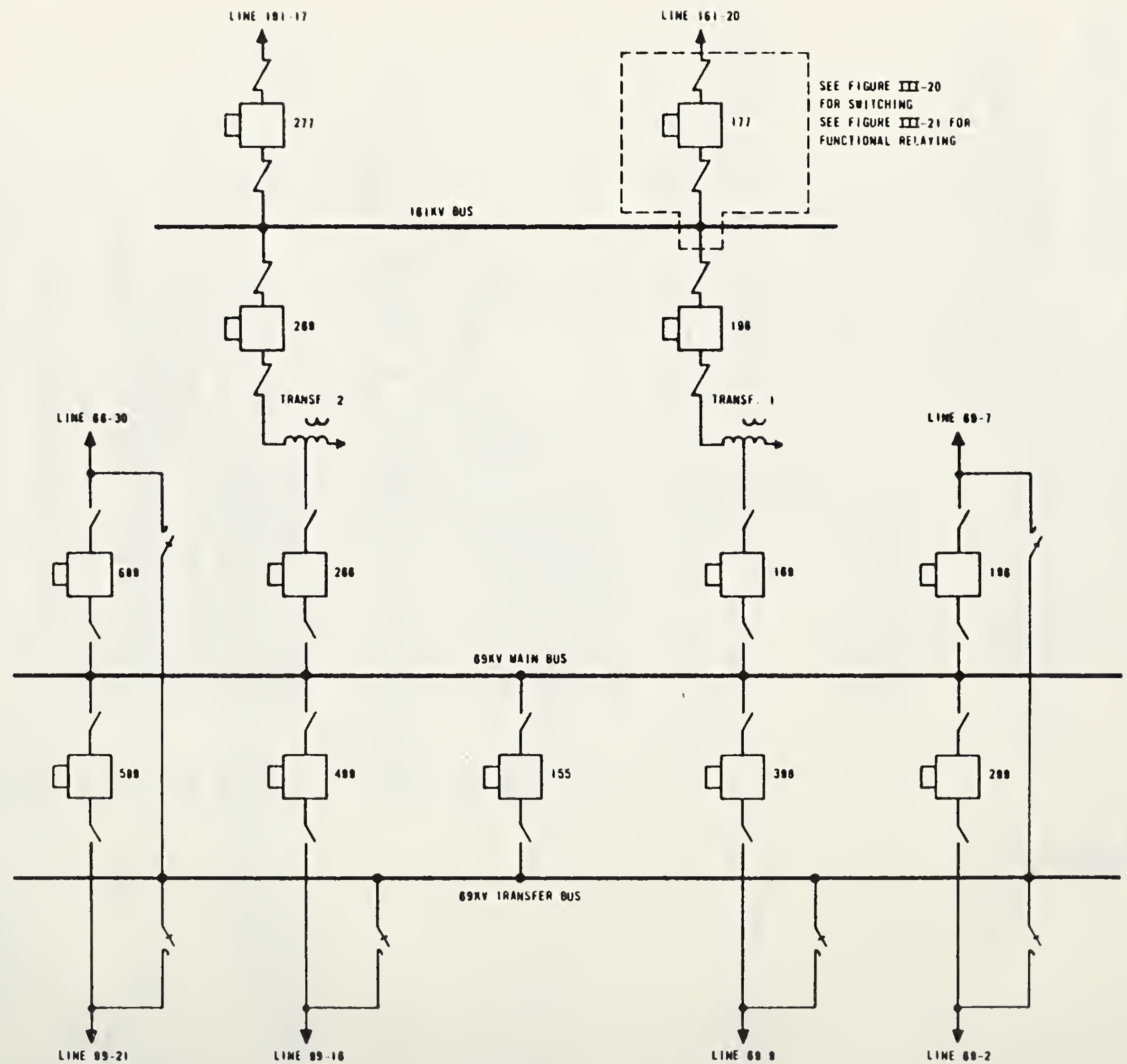


FIGURE III-19 CONCEPTUAL ONE LINE DIAGRAM

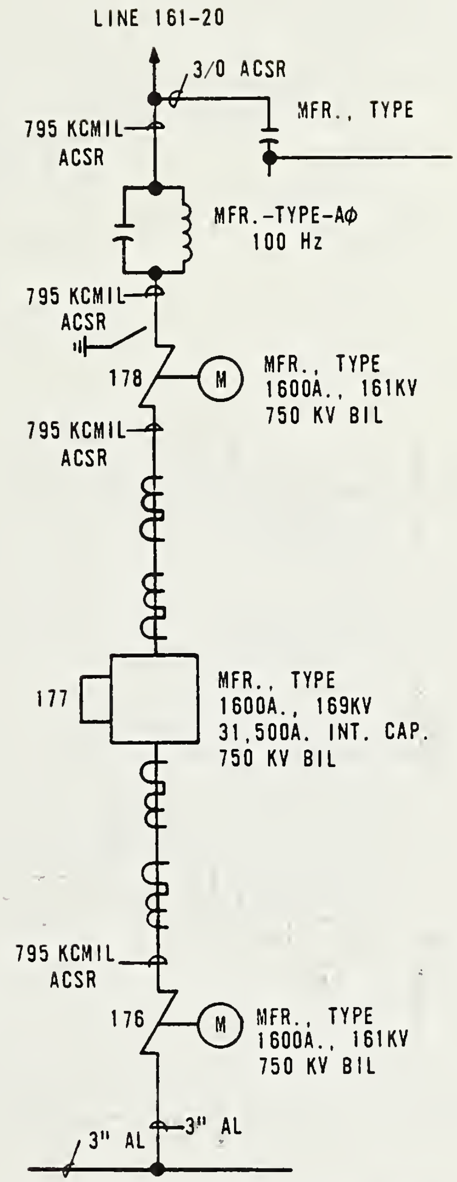


FIGURE III-20 PARTIAL SWITCHING ONE LINE DIAGRAM (SEE FIGURE III-19)

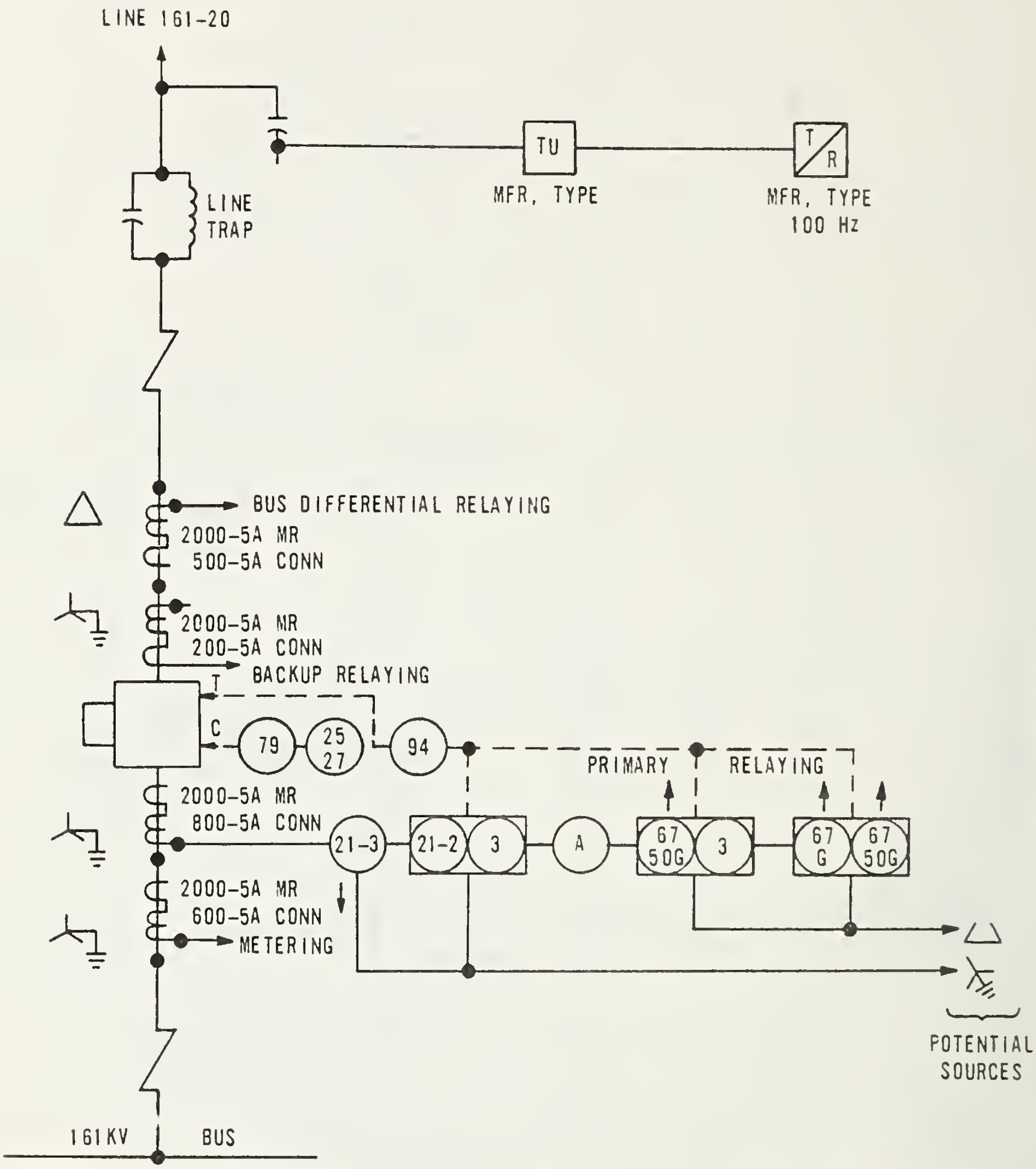


FIGURE III-21 PARTIAL FUNCTIONAL RELAYING ONE LINE DIAGRAM (SEE FIGURE III-19)

of the symbols. Figures III-20 and III-21 combined give a more complete equipment usage for Line 161-20. It may be observed that equipment shown on Figures III-20 and III-21 hardly exhausts the possibilities of equipment application for a 161 kV line. These figures, moreover, indicate the desirability of having both switching and relaying One Line Diagrams except for the simpler substations.

c. Three Line Diagram

d. Electrical Plot Plan

e. Site Preparation

f. Fence Layout

g. Electrical Layouts

h. Structure Erection Diagrams

i. Foundation Layouts

j. Grounding Layout

k. Conduit Layout

l. Control House - Architectural, Equipment, Layout, Lighting, etc.

m. Station Service Diagrams AC and DC

n. Cable Lists and Conduit Lists

Cables may be listed on a drawing, such as a conduit layout, if the number of cables is not large. On large stations, it generally is desirable to have a separate cable list. A cable identification system should be devised related to the location of one end of a cable and to the function of the cable.

An alpha-numeric designation often works well. In such a system, C4-3 could be a cable from a circuit breaker at location C4 on a grid system where C designates an equipment row centerline in a series A, B, C, D, etc. and 4, designates a row centerline in a series 1,2,3,4,5,6, etc., at a right angle to centerline C. The -3 could represent a cable for control.

Different arabic numerals could be used for other functions.

o. Bills of Material

As a general rule, all elements of work in a substation should have a list of material. When such lists comprise a multisheet drawing, they are known as Bills of Material. Formats should be devised to include the following information as a minimum:

(1) Identification of substation

(2) Alpha-numeric code name for items that may appear on a construction drawing for identification and location

(3) Adequate description of item

(4) Reference to applicable purchasing document

(5) Quantity of item

(6) Reference to drawing(s) on which item is shown for installation

p. Drawing List

It is recommended that every substation have a drawing list to include, at the Borrower's and Engineer's discretion, manufacturers' drawings, design calculations, Borrower's standard drawings, etc.

q. Control Panels

r. Schematic & Detail Wiring Diagrams

These should be prepared following the guidelines in ANSI Standard Y14.15, "Electrical and Electronic Diagrams."

F. STUDIES

For many substations, it will be necessary to make a number of studies such as feasibility studies, economic comparisons, voltage drop calculations for control and auxiliary power circuits, rigid and strain bus design comparisons, structural

design calculations, etc. The results of these studies along with the Calculations should be retained with other documents relating to the particular substation.

APPENDIX

DRAWING CHECKLIST
APPLICABLE TO ALL DRAWINGS

Checker's Initials	Item
________	Drawing is of material satisfactory to Borrower
________	Drawing is of a size satisfactory to Borrower
________	Drawing is identified as satisfactory to Borrower
________	Drafting Practice is in accordance with Chapter III, Section E2
________	All line work and lettering are reproducible
________	The smallest lettering is readable at the smallest proposed reduction size
________	Has consideration been given to overall organization of drawing to minimize field inconvenience?
________	Does the drawing avoid ambiguities, incompleteness, lack of clarity, misleading emphasis, etc? (If a mistake is made in construction it could be that the drawing, although not being wrong, could have been clearer.)
________	Legends, notes, symbols have been carefully reviewed for correctness and completeness
________	Appropriate drawings referenced
________	All changes incorporated as required by Borrower or REA

SWITCHING ONE-LINE DIAGRAM CHECKLIST

Checker's Initials	Item
________	General requirements, applicable to all drawings, have been met
________	Acceptable symbols are used; reference Chapter III, Sec. E 3.b (8)
________	Symbols are arranged, as much as practical, the same as the represented equipment
________	North orientation is the same as Electrical Plot Plan
________	Major equipment numbering scheme meets Borrower's requirements
________	Buses and circuit connections are identified in accordance with Borrower's requirements
________	Vector relations and phasing are shown where pertinent
________	Symbols and line widths are sized so that those for major equipment are more prominent than those for less important equipment
________	Symbols and lettering are so proportioned with respect to each other that the drawing is easy to read
________	Lines representing conductors have widths relative to, though not necessarily in direct proportion to, their current carrying ability
________	All insulated conductors are identified as to number per phase, voltage class, conductor size and material, and insulation type
________	All uninsulated conductors are identified as to number per phase, size and material
________	Substation phasing relative to geographical is shown by a three line detail near the north arrow

SWITCHING ONE-LINE DIAGRAM CHECKLIST (cont'd)

Checker's Initials	Item
_________	Reference is made to Electrical Plot Plan and Functional Relaying One-Line Diagram
_________	Substation ac service is shown at least to include the transformer(s) and ac service diagram is referenced
_________	Any unusual manual switching constraints are enumerated in the Notes
_________	Conform to short range and long range requirements of Power Supply Study
_________	Conform to requirements of two-year work plan
_________	Agrees with conceptual one-line of authorization document
_________	Agrees with all other drawings such as Electrical Plot Plan and Electrical Layouts
_________	No conflict with major equipment as may have been previously specified or allocated

FUNCTIONAL RELAYING ONE-LINE DIAGRAM CHECKLIST

Checker's Initials	Item
________	General requirements, applicable to all drawings, have been met
________	Arrangement of symbols is as close as practical to that of switching one-line diagram
________	Major equipment identification, conductor identification, and surge arresters are not shown
________	Current transformer polarity marks, overall ratios, and connected ratios are shown
________	All protective relays are shown by appropriately numbered symbolic circles
________	Each device in a current transformer circuit is shown in the same order as the actual wired connection
________	Voltage transformer ratios and secondary winding protection are shown
________	Instrument transformer connection are indicated by appropriate symbolism for delta or wye connections and grounded or ungrounded
________	Reference is made to switching one-line diagrams and control and relay panel front views
________	Lines representing current transformer connection (preferred horizontal) and lines representing potential connections (preferred vertical) contact relay or meter symbols at right angles to each other
________	Arrows are shown near protective relay to indicate direction of fault that calls for circuit breaker tripping
________	Notes have been made covering desired action upon operation of differential, transfer trip, breaker failure relays, etc.

Checker's Initials	Item
________	Legend includes only symbols not covered on switching one-line diagram
________	Appropriate symbolism has been developed for supervisory control, telemetering, communication links, etc.
________	DC auxiliary relays shown
________	Trip and interlock-functions shown

DRAWING CHECKLIST
ELECTRICAL PLOT PLANS

Checker's Initials	Item
________	General requirements, applicable to all drawings, have been met
________	North orientation is same as one-line diagram(s)
________	Agrees with one-line diagram
________	Circuit connection phase conductors and shield wires have been verified with transmission and distribution authorities as to size, material, take-off points, and direction; shielding for direct stroke lightning protection meets required criteria
________	Switching one-line diagrams, electrical layouts, foundation layouts, site preparation, and other pertinent construction drawings are consistent and appropriately referenced

U.S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION
SUBSTATION DESIGN SUMMARY

I. INTRODUCTION

A. GENERAL

1. This summary provides basic information on substation requirements and design.

2. The summary will be updated as the project progresses from initial design to in-service status. In its final form it will be, with supporting and reference documents, a complete record of the substation.

B. BASIC IDENTIFICATION DATA

1. Substation Name ____________________

2. Borrower's Designation and Name ____________________

   ____

3. Location ____________________

4. Summary Prepared by ____________________

   Date ____________________

   Revision "A" Prepared by ____________________

   Date ____________________

   (As many listings as necessary. Whenever a revision is made, a notation should be entered in the left hand margin-adjacent to the item revised.)

C. SCHEDULE

	Proposed or Record Date
1. Pre-Design (identify documentation of each item for record)	

	Proposed or Record Date
a. Environmental impact statement or brief environmental report	______
b. Site purchase and title clearance	______
c. Topographical survey	______
d. Ambient noise level survey	______
e. Surrounding land use survey	______
f. Soil borings	______
g. Soil resistivity measurement	______
2. Design	
a. One-line diagram and general layout for Borrower's approval	______
b. Detail design for Borrower's approval (List individual areas such as foundations, structures, electrical below grade, electrical above grade, and protective relaying if separate submittals are required.)	______
c. Design complete	______
3. Procurement (itemize as listed below for each set of equipment, material, and hardware)	
a. Specification for Borrower's approval	______
b. Invite bids	______

	Proposed or Record Date
c. Pre-bid meeting with vendors or contractors (sometimes advantageous for major equipment or construction)	
d. Receive bids	
e. Bid opening (usually construction only)	
f. Evaluation of bids	
g. Pre-award meeting (sometimes advantageous with major equipment or construction)	
h. Award contract	
i. Delivery (equipment, material or hardware)	
4. Construction	
a. Begin construction	
b. Complete site grading	
c. Complete drainage	
d. Complete roadways	
e. Complete fence	
f. Begin foundations, conduit, and grounding	
g. Complete below grade	
h. Begin above grade	
i. Complete outdoor yard	
j. Complete control house	

Proposed or Record Date

k. Complete testing (list documents) ____________

l. Complete inspection (list documents) ____________

m. In-service ____________

D. <u>PERMITS AND LICENSES</u>

List all permits and licenses that will be required prior to and during construction. ____________

E. <u>REFERENCES</u>

1. Power supply study (identify) ____________

2. Two Year Work Plan (identify) ____________

3. Conceptual one-line diagram (identify) ____________

II. DESIGN CONSIDERATIONS

A. <u>INITIAL AND ULTIMATE REQUIREMENTS</u>

1. Nominal Operating Voltages (itemize as listed below for each voltage)

a. Voltage __________ kV

b. Connection (delta or wye) __________

c. Phase rotation __________

d. Phase displacement with respect to other voltages (leads or lags) __________ __________ kV by __________°

2. Capacity

a. Voltage Transformations (itemize as listed below for each transformation)

(1) Initial

(a) High voltage __________ kV

(b) Low voltage __________ kV

(c) Capacity __________ MVA

(2) Ultimate (if different than initial)

(a) High voltage __________ kV

(b) Low voltage __________ kV

(c) Capacity __________ MVA

b. Circuit Connections (itemize as listed below for each connection)

(1) Initial

(a) Voltage __________ kV

(b) Quantity __________

(2) Ultimate

(a) Voltage __________ kV

(b) Quantity __________

c. Bus Configurations (itemize as listed below for each bus)

(1) Initial

(a) Nominal bus voltage __________ kV

(b) Configuration (single bus, sectionalized bus, main and transfer bus, ring bus, breaker-and-a-half, double breaker-double bus)

____

(2) Ultimate

(a) Nominal bus voltage __________ kV

(b) Configuration (single bus, sectionalized bus, main and transfer bus, ring bus, breaker-and-a-half, double breaker-double bus)

____

d. Current Carrying Requirements (itemize as listed below for each bus and circuit connection)

(1) Bus or circuit connection description

____

(2) Nominal voltage __________ kV

(3) Ampacity

(a) Continuous __________ amperes

(b) 24 hour temporary __________ amperes

e. Ultimate Power Supply Fault Conditions

(1) Three phase fault __________ amperes

(2) Phase to phase fault __________ amperes

(3) Phase to ground fault __________ amperes

f. Maximum Permissible Fault Clearing

Time __________ seconds

B. SITE

State any unusual constraints imposed on the design because of site characteristics.

C. ENVIRONMENTAL

1. State that design is in accordance with Environmental Impact Statement (identify) or Brief Environmental Report (identify).

2. Describe, in general, any design measures taken to enhance appearance.

3. State the necessity for any unusual cost items related to public safety.

4. State the rationale for noise contribution.

5. State the expected electrostatic and electromagnetic effects.

6. State the rationale for effluent design. Recommend that a design be made for a plan of action to prevent pollution if this is so indicated.

D. <u>NATURE</u>

1. Weather

   a. State any unusually severe possible local conditions that the substation is not designed to withstand.

   b. State what design measures have been taken with respect to any special local condition.

2. Temperatures

   a. Average annual temperature

      (1) Maximum __________°C (__________°F)

      (2) Minimum __________°C (__________°F)

   b. Highest recorded temperature _____°C (_____°F)

   c. Lowest recorded temperature _____°C (_____°F)

3. Wind and Ice Loading (itemize as listed below for line support structures, equipment support structures, and conductors)

   a. Wind

      (1) Velocity __________km/hr (__________mph)

      (2) Safety factor __________

      (3) Gusts __________km/hr (__________mph)

      (4) Safety factor __________

b. Ice

(1) Thickness __________ cm (__________in)

(2) Safety factor __________

4. Precipitation

a. Design rainfall

(1) Amount __________ cm/hr (__________in/hr)

(2) Period __________ hours

(3) Frequency of storm occurence __________

b. Design snowfall

(1) Maximum drift depth _____ m (_____ft)

c. Electrical storms

(1) Isokeraunic level __________ thunderstorm days per year

d. Humidity

State design measures.

5. Altitude Above Mean Sea Level _____ m (_____ft)

6. Seismic Risk Zone __________

7. Wildlife Protection

State any unusual measures required.

8. Airborne Foreign Material Protection

State materials protecting against.

III. DOCUMENTS

A. AUTHORIZING DOCUMENT FOR DESIGN

____

____

B. <u>DISTRIBUTION OF DOCUMENTS</u> (itemize as listed below for each document)

1. Document Description ______________________________

2. Name and Address of Recipient

____

____

____

3. Number of Copies ____________________

C. <u>REA PROCEDURES</u> (to be checked with)

1. Name and Address of REA Field Representative

____

____

____

D. <u>PROCUREMENT</u>

1. Major Equipment (itemize as listed below for each major piece of equipment)

a. Description of Equipment ____________________

____

b. Name and Address of Manufacturer

____

____

____

c. Contract number __________________

d. Purchase order number __________________

2. Construction Contracts (itemize as listed below for each contract)

   a. Description of contract ______________________

      ____

   b. Name and Address of Contractor

      ____

      ____

      ____

   c. Contract number ____________________

   d. Purchase order number ____________________

3. Equipment Materials, and Hardware (itemize as listed below for each item)

   a. Description of item ___________________________

      ____

   b. Name and Address of Manufacturer

      ____

      ____

      ____

   c. Purchase order number ____________________

E. <u>DRAWING LIST OR DRAWING LIST NUMBER</u>

Provide list of drawings or drawing list number.

F. <u>STUDIES</u>

Describe the studies that are required.

IV. PHYSICAL LAYOUT

A. SUBSTATION TYPE (distribution, transmission, switching)

____

B. TYPE OF DESIGN (Borrower's standard, packaged, custom)

____

C. CIRCUIT CONNECTIONS (itemize as listed below for each connection)

1. Overhead Circuits

a. Nominal voltage __________ kV

b. Quantity __________

c. Conductor size, type, and material ___________

d. Pull-off elevation __________ m (__________ft)

e. Maximum tension __________ N (__________lb)

(1) Temperature __________°C (__________°F)

(2) Ice thickness __________ cm (__________in)

(3) Wind velocity _____ km/hr (_____mph)

f. Shield wires

(1) Quantity of shield wires per connection ______

(2) Wire size, type, and material ___________

(3) Pull-off elevation _____ m (______ft)

(4) Maximum tension (at same conditions as phase conductors) _______ N (______lb)

5. Underground Circuits

a. Nominal voltage __________ kV

b. Quantity __________

c. Conductor size, type, material, and insulation

____

____

D. <u>DISTRIBUTION SUBSTATIONS</u> (only)

1. Provisions for Mobile Transformer (yes or no) _____

2. Provisions for Mobile Substation (yes or no) ______

3. Provisions for Future Addition of (describe) ______

____

4. Provisions for Source Voltage Change (yes or no) _______

a. Initial voltage __________ kV

b. Ultimate voltage __________ kV

c. Change of (describe) _________________________

____

5. Provisions for Load Voltage Change (yes or no) _________

a. Initial voltage __________ kV

b. Ultimate voltage __________ kV

c. Change of (describe) _________________________

____

E. <u>TRANSMISSION SUBSTATIONS</u> (only)

1. Provisions for Future Addition of (describe) ______

____

2. Provisions for Source Voltage Change (yes or no) _______

a. Initial voltage __________ kV

b. Ultimate voltage __________ kV

c. Change of (describe) __________________________

____

3. Provisions for Load Voltage Change (yes or no) ____

a. Initial voltage __________ kV

b. Ultimate voltage __________ kV

c. Change of (describe) __________________________

____

F. SWITCHING SUBSTATIONS (only)

1. Provisions for Future Addition of (describe) ______

____

2. Provisions for Voltage Change (yes or no) _________

a. Initial voltage __________ kV

b. Ultimate voltage __________ kV

c. Change of (describe) __________________________

____

G. BUS CONFIGURATION (itemize as listed below for each bus)

1. Initial

a. Nominal bus voltage __________ kV

b. Configuration (single bus, sectionalized bus, main and transfer bus, ring bus, breaker-and-a-half, double breaker-double bus) _____________

2. Ultimate (if different than initial)

a. Nominal bus voltage __________ kV

b. Configuration (describe) ____________________

____

H. DIRECT STROKE SHIELDING

1. Shielding Measures (rods, wires, masts) (describe)

____

2. Shielding Angles

a. Angle from vertical for single rod, wire, or mast __________°

b. Angle from vertical for adjacent rods, wires, or masts __________°

I. INSULATORS (itemize as listed below for each voltage)

1. Apparatus Insulators

a. Nominal voltage __________ kV

b. Type (cap and pin or post) __________

c. BIL __________ kV

d. Color __________

e. Cantilever strength _______ N (_______lb)

f. NEMA TR No. (or other description) ___________

____

2. Suspension Insulators

a. Nominal voltage __________ kV

b. Quantity per string __________

c. Color __________

d. M-E strength __________ N (__________lb)

e. ANSI Class (or other description) ____________

____

J. ELECTRICAL CLEARANCES (itemize as listed below for each voltage)

1. Nominal voltage ________ kV

		Rigid Conductors	Non-Rigid Conductors
2.	Minimum Metal-to-Metal	_____cm(_____in)	_____cm(_____in)
3.	Minimum Phase to Grounded Parts	_____cm(_____in)	_____cm(_____in)
4.	Minimum Phase to Substation Grade	_____m(_____ft)	_____m(_____ft)
5.	Minimum Phase to Substation Roadway	_____m(_____ft)	_____m(_____ft)
6.	Centerline-to-Centerline Phase Spacing	_____m(_____ft)	_____m(_____ft)

K. BUS AND ELECTRICAL CONNECTIONS (itemize as listed below for each case)

1. Nominal Voltage ________ kV

2. Type of Connection (describe) ____________________

3. Rigid Conductors (clamp, bolted, welded) __________

4. Non-Rigid Conductors (clamp, compression, welded) ____________

5. Fasteners (describe) ____________________________

____

L. RIGID BUSES (itemize as listed below for each bus)

1. Conductor Size, Type, and Material ______________

2. Design Short Circuit Current (three phase symmetrical) __________ rms amperes

3. Wind and Ice Loading (see Section II.D.3)

4. Support Insulator Spacing __________m (__________ft)

5. Factor of Safety for Support Insulators __________

6. Maximum Conductor Sag Without Ice _______________

7. Maximum Conductor Sag With Ice ________________

8. Measures for Prevention of Aeolian Vibration ______

____

9. Provisions for Conductor Expansion ______________

____

M. STRAIN BUSES (itemize as listed below for each bus)

1. Conductor Size, Type, Stranding, and Material

____

2. Wind and Ice Loading (see Section II.D.3)

3. Span Length __________ m (__________ft)

4. Factor of Safety for Suspension Insulators ________

5. Sag and Tension at Maximum Loading Conditions ______ m (______ft) sag at ______ N (______lb) tension

6. Sag and Tension at 25°C (77°F) ______ m (______ft) sag at ______ N (______lb) tension

7. Sag and Tension at 70°C (167°F) ______ m (_____ft) sag at ______ N (______lb) tension

V. MAJOR EQUIPMENT (itemize as listed below for each different component)

A. POWER TRANSFORMERS

1. Type (auto, multi-winding, 3-phase, 1-phase) ______

2. Quantity __________

3. Dielectric (oil, air, or gas) __________

4. Rating ______/______/______ MVA

5. Cooling (OA, OA/FA, OA/FA/FA, OA/FOA, OA/FA/FOA, OA/FOA/FOA) ____________________

6. Average Winding Temperature Rise (55°C, 65°C) _____

7. Primary Voltage __________ kV

   a. No-load taps ________________

8. Secondary Voltage __________ kV

   a. No-load taps ________________

9. Tertiary Voltage __________ kV

   a. No-load taps ________________

10. Load-Tap-Changer (LTC)

    a. Percent above and below nominal voltage ______

    b. Winding (primary or secondary) _______________

11. BIL

    a. Primary winding __________ kV

    b. Secondary winding __________ kV

    c. Tertiary winding __________ kV

B. <u>POWER CIRCUIT BREAKERS</u>

1. Type (dead tank or live tank) _____________________

2. Quantity __________

3. Interrupting Medium (oil, air, gas, vacuum) _______

4. Nominal Voltage __________ kV

5. Maximum Voltage __________ kV

6. Rated Voltage Range Factor (K) __________

7. Continuous Current __________ rms amperes

8. Short-Circuit Current at Rated Maximum Voltage __________ rms amperes

9. Maximum Symmetrical Interrupting Capability __________ rms amperes

10. 3-Second Short Time Current Capability __________ rms amperes

11. Closing and Latching Capability _______ rms amperes

12. Interrupting Time __________ cycles

13. Type of Operating Mechanism (solenoid, motor, pneumohydraulic, pneumatic, motor-changed spring, manual-charged spring, manual) ___________________________

14. Control Power Voltage __________ VAC __________ VDC

15. Auxiliary Power Voltage __________ VAC

C. METAL-CLAD SWITCHGEAR

1. Nominal Voltage __________ kV

2. Indoor or Outdoor __________

3. Switching Scheme (describe) _______________________

____

4. Continuous Current __________ amperes

5. Maximum RMS Momentary Current __________ ka

6. Circuit Breaker Interrupting Capability ______ amperes

D. SUBSTATION VOLTAGE REGULATORS

1. Type (step or induction, single or three phase)

____

2. Quantity __________

3. Nominal Voltage __________ kV

4. Rating _______ kVA

5. Percent Regulation + __________%, - __________%

E. SHUNT CAPACITOR EQUIPMENT

1. Type (open rack or housed) ________________________

2. Quantity __________

3. Nominal Voltage __________ kV

4. Bank Rating __________kVAR

5. Individual Units

   a. Voltage __________ kV

   b. Rating __________ kVAR

6. Connection (delta, wye, grounded wye, double wye)

   ____

F. AIR SWITCHES

1. Type (disconnecting, grounding, horn-gap, interruptor, selector) _______________________________

2. Quantity __________

3. Construction (vertical break, double break, tilting insulator, side break, center break, vertical reach)

   ____

4. Operating Mechanism (hook stick, manual mechanism, motor mechanism) __________________________________

5. Poles (single or three) ___________________

6. Nominal Voltage __________ kV

7. Continuous Current __________ amperes

8. Momentary Current __________ amperes

9. Interrupting Current __________ amperes

G. SURGE ARRESTERS

1. Type (station, intermediate, distribution) ________

2. Quantity __________

3. Voltage Rating _________ kV

4. Nominal System Voltage __________ kV

5. For Protection of (describe) ______________________

____

H. AUTOMATIC CIRCUIT RECLOSERS

1. Quantity __________

2. Nominal Voltage __________ kV

3. Continuous Current __________ amperes

4. Interrupting Current __________ amperes

5. Single or Three Phase __________

6. Interrupting Medium (oil, vacuum) __________

7. Control (Hydraulic or electronic) __________

8. Coil Tripping (series, non-series) __________

9. Closing (spring, solenoid, motor) __________

10. Minimum Tripping Current __________ amperes

11. Operational Sequence to Lockout (describe)

____

I. CURRENT TRANSFORMERS

1. Type (bar, window, bushing, other) __________

2. Quantity __________

3. Nominal Voltage __________ kV

4. BIL __________ kV

5. Ratio(s) ____________________

6. Accuracy (metering or relaying) __________

7. Accuracy Class __________

8. Burden __________

J. VOLTAGE TRANSFORMERS

1. Type (cascade, grounded neutral, insulated neutral, single high voltage line terminal, double high voltage line terminal) ____

2. Quantity __________

3. Nominal Voltage __________ kV

4. BIL __________ kV

5. Ratio(s) __________

6. Accuracy __________

7. Burden __________

K. COUPLING CAPACITORS AND COUPLING CAPACITOR VOLTAGE TRANSFORMERS

1. Type (CC or CCVT) __________

2. Quantity __________

3. Nominal Voltage __________ kV

4. BIL __________ kV

5. Capacitance __________ henries

6. Carrier Accessories (yes or no) __________

7. Voltage Transformer (yes or no) __________

    a. Ratio(s) __________

L. MOBILE UNITS

1. Type (transformer, substation) ___________

2. Quantity __________

3. Primary Voltage __________ kV

4. Secondary Voltage __________ kV

5. Capacity ___________ MVA

6. Accessories (list and describe) ___________________

    ____

    ____

    ____

VI. SITE

A. GENERAL

1. Yard Type (flat, sloped, stepped) __________

2. Nominal Finished Grade Elevation(s)

    __________ m (___________ft) with

    __________ % slope

3. Topographical Drawing Reference __________

4. Soil Boring Reference __________

B. DRAINAGE

1. Type of System (surface or closed) __________

2. Design Basis (see Section II.D.4)

3. Time for Run-Off from Remotest Part of Drainage Area __________ hours

C. EARTHWORK

1. Excess Top Soil __________ m^3 (__________ yd^3)

2. Fill Required __________ m^3 (__________ yd^3)

3. Earth to be Moved Exclusive of Excess Top Soil

   __________ m^3 (__________ yd^3)

D. ROADS (itemize as listed below for each access road, interior road, and railroad)

1. Length __________ m (__________ ft)

2. Width __________ m (__________ ft)

3. Maximum Grade __________ %

4. Minimum Inside Curve Radius

   __________ m (__________ ft)

5. Base Course __________

6. Wearing Course __________

7. Maximum Equipment Load ________ kg/axle (______ lb/axle)

E. EROSION PROTECTION

State basic description.

F. YARD SURFACING MATERIAL

1. Material

   a. Type __________

   b. Size __________

2. Material Placement

   a. Area ____________________________

   b. Layer depth __________ cm (__________ in)

G. SECURITY FENCE

1. Height __________ m (__________ft)

2. Fabric Gauge __________

3. Fabric Material __________

4. Gates (itemize as listed below for each size gate)

   a. Size __________ m (__________ft)

   b. Quantity __________

5. Depth of Post Footing Holes _______ m (______ft)

VII. STRUCTURES

A. LINE SUPPORT STRUCTURES

1. Material ____________________

2. Protective Coating or Treatment ___________________

3. Loading Criteria

   a. Conductors _______ N (_______lb) per phase

   b. Shield wires _______ N (_______lb) per wire

   c. Equipment weight __________ kg (__________lb)

   d. Wind and ice loads (see Section II.D.3)

   e. Seismic (describe) ___________________________

   ____

4. Overload Factor _______________________

5. Unit Stress Limit _____________________

6. Deflection Limits _____________________

7. Fasteners (describe) ______________________________

   ____

B. EQUIPMENT SUPPORT STRUCTURES

1. Material ____________________

2. Protective Coating or Treatment ________________

3. Loading Criteria

   a. Equipment weight ________ kg (________lb)

   b. Short circuit force _____ N/m (_____lb/ft)

   c. Wind and ice loads (see Section II.D.3)

   d. Seismic (describe) ______________________

   ____

4. Unit Stress Limit ____________________

5. Deflection Limits ____________________

6. Rigidity Considerations ______________________

   ____

7. Fasteners (describe) ________________________

   ____

VIII. FOUNDATIONS

A. SOIL

1. Type ________________

2. Allowable Soil Bearing Pressure _____ N/m^2 (____psf)

3. Describe Other Soil Capability Limitations _______

   ____

   ____

4. Ground Water Elevation ________ m (________ft)

B. DESCRIPTION OF CONCRETE

1. Type ______________________________________

2. Minimum 28 Day Compressure Strength

__________ N/cm^2 (__________psi)

3. Depth Below Grade to Withstand Frost

__________ m (__________ft)

C. DESCRIPTION OF REINFORCING BAR

Describe the reinforcing bar used in each type of foundation.

D. OIL POLLUTION ABATEMENT

Describe methods for oil pollution abatement.

E. FOUNDATION TYPES

Describe each type of foundation (augered pin, spread footing, slab) and its function.

IX. GROUNDING

A. Total Ultimate Fault Current __________ amperes

B. Portion of Ultimate Fault Current Which Can Flow Through Earth into Grounding Grid __________ amperes (total current less that which flows to system neutral through shield wires)

C. Shock Duration (fault clearing time) __________ seconds

D. Average Earth Resistivity __________ohm-meters

1. Depth __________ cm (__________in)

2. Date Measured __________

E. Grid Conductor

1. Size __________

2. Length __________ m (__________ft)

F. Ground Rods

1. Quantity __________

2. Size

a. Diameter __________ cm (__________in)

b. Length __________ m (__________ft)

G. Allowable Voltages

1. E_{step} __________ volts

2. E_{touch} __________ volts

3. Surface Resistivity __________ ohm-meters

H. Calculated voltages

1. E_{step} __________ volts

2. E_{touch} __________ volts

3. If calculated voltages are much less than allowable voltages, explain

____

____

____

I. Substation Area __________ m^2 (__________ft^2)

J. Peripheral Ground Wire (describe) ______________________

____

____

X. INSULATED CABLES AND RACEWAYS

A. CABLES (itemize as listed below for each type of cable)

1. Type (control or power) __________

2. Voltage Rating __________ volts

3. Conductor Size, Type, and Material ________________

____

4. Number of Conductors _________________

5. Quantity __________ m (___________ft)

6. Insulation

   a. Type (PVC, PE, PVC(I), XLPE(I), SLPE, RULAN)

   ____

   b. Thickness __________ mils

7. Jacket

   a. Type (neoprene or PVC)

   b. Thickness over each conductor __________ mils

   c. Thickness over entire cable __________ mils

B. <u>RACEWAYS</u> (itemize as listed below for each type of raceway)

1. Conduit

   a. Material _________________________

   b. Size __________ cm (__________in)

2. Duct Bank

   a. Size

      (1) Width __________ m (__________ft)

      (2) Depth __________ m (__________ft)

      (3) Number of conduits

         (a) Width __________

         (b) Depth __________

(4) Size of conduits ______ cm (______in)

3. Cable Trench

a. Type (concrete block, cast in place concrete, or precast concrete) ______________________

b. Width __________ cm (__________in)

c. Depth __________ cm (__________in)

XI. CORROSION

A. State Rationale for the Provision (or lack of it) of a Cathodic Protection System

B. CATHODIC PROTECTION SYSTEM

1. Summary of Soil Resistivity Survey

____

____

____

____

2. Summary of PH Survey

____

____

____

____

3. Basic Description of Protection System

____

____

____

____

XII. PROTECTIVE RELAYING

A. State the General Philosophy of the Protective Relaying Systems: Coordination Required With Other Parts of the System, Expected Fault Currents for Various Conditions, Speed of Interruption Sought for Various Cases, etc.

B. TRANSMISSION LINE PROTECTION (itemize as listed below for each line)

1. Line Destination or Description ____________________

2. Nominal Voltage __________ kV

3. Protection Scheme (phase comparison, directional comparison, direct underreach, permissive underreach, permissive overreach, overcurrent-describe) _______

   ____

4. Automatic Reclosing (yes or no-describe) __________

   ____

5. Relays (list) ______________________________________

   ____

C. TRANSFORMER AND REACTOR PROTECTION (itemize as listed below for each transformer and reactor)

1. Transformer or Reactor Number or Description ______

2. Nominal Voltages (Primary/tertiary/secondary)

   __________/__________/__________ kV

3. Protection Scheme (differential, sudden pressure, directional phase distance, ground overcurrent-describe)

   ____

   ____

4. Relays (list) ______________________________________

   ____

D. BUS PROTECTION (itemize as listed below for each bus)

1. Bus Number or Description ______________________

2. Nominal Voltage _________ kV

3. Protection Scheme (current differential, voltage differential-describe) ____________________________

____

4. Relays (list) _________________________________

____

E. BREAKER FAILURE PROTECTION

1. Where Applied (describe) _______________________

____

2. Relays (list) _________________________________

____

F. DISTRIBUTION LINE PROTECTION (itemize as listed below for each line)

1. Line Destination or Description _________________

2. Nominal Voltage _________ kV

3. Protection Scheme (overcurrent relaying, automatic circuit reclosers, sectionalizers, fuses-describe)

____

4. Relays and Equipment (list) _____________________

____

XIII. INSTRUMENTS, TRANSDUCER, AND METERS

Describe metering systems and list equipment for each system.

XIV. AC AND DC AUXILIARY SYSTEMS

A. AC SYSTEM

1. Connected AC Load __________ kVA

2. Overall Demand Factor ____________%

3. Auxiliary Transformer

   a. Rating __________ kVA

   b. Voltage (primary/secondary) ________/________ kV

4. Normal Source (describe) __________________________

   ____

5. Alternate Source (describe) _______________________

   ____

6. Auxiliary System Voltage (480/277 volts, wye connected, three phase, four wire; 208/120 volts, wye connected, three phase, four wire; 240/120 volts, delta connected, three phase, four wire; 240/120 volts, open delta connected, three phase, four wire; 240/120 volts, single phase, three wire) __________

   ____

7. Transfer Switch (describe) ________________________

   ____

8. Asymmetrical Fault Current at Main Panelboard or Switchboards __________ amperes

9. Panelboards and Switchboards (describe) ___________

   ____

   ____

10. Outdoor Lighting

    a. Objective (describe) __________________________

    ____

b. Luminaires (describe) ________________________

____

c. Switching method (describe) __________________

____

B. <u>DC SYSTEM</u>

1. DC System Loads (list) ____________________________

____

2. Nominal Voltage __________ volts

3. Battery

a. Ampere-hours __________________

b. Number of cells _______________

4. Battery Charger (describe) _______________________

____

XV. CONTROL HOUSE

A. <u>INSIDE DIMENSIONS</u>

1. Length __________ m (__________ft)

2. Width __________ m (__________ft)

3. Clear Height __________ m (__________ft)

B. <u>BASEMENT</u> (yes or no) _______________

C. <u>FOUNDATION</u>

1. Footings

a. Width __________ cm (__________in)

b. Depth __________ m (__________ft)

c. Depth below grade _______ m (_______ft)

2. Foundation Walls

   a. Type (cast in place concrete or concrete block)

      ____

   b. Perimeter Insulation (yes or no) ____________

      1. Type ________________________

      2. Thickness __________ cm (__________in)

      3. Location (inside or outside of walls)

         ____

3. Floor

   a. Thickness __________ cm (__________in)

   b. Reinforcing (describe) _______________________

      ____

   c. Cast in Concrete Cable Trench (yes or no) (describe)

      ____

      ____

D. <u>SUPERSTRUCTURE</u>

1. Type (pre-engineered metal or concrete block) _____

   ____

2. Roof Type (precast, prestressed concrete panels or steel joists and steel decks) _____________________

3. Doors (itemize as listed below for each door size)

   a. Size _______ cm (_______in) x _______ cm

      (__________in)

   b. Quantity __________

4. Windows (itemize as listed below for each window size)

   a. Size _______ cm (_______in) x _______ cm (_________in)

   b. Quantity __________

E. CONTROL PANELS

1. Type (single, double, or duplex) __________________

2. Function (list each panel) ________________________

   ____

3. Size __________ cm (__________in) x __________ cm (__________in)

F. CABLE TRAYS

1. Size __________ cm (__________in)

2. Method of Support (describe) ______________________

   ____

G. LIGHTING

1. Average Illumination __________ lumens/m^2 (__________ lumens/ft^2)

2. Luminaires (describe) _____________________________

   ____

   ____

3. Emergency lighting (describe) _____________________

   ____

H. AIR CONDITIONING EQUIPMENT

1. Number of Units ________________

2. Type of Units __________________

3. Rating ______________

I. HEATING EQUIPMENT

1. Number of Units _________________

2. Type of Units ___________________

3. Rating ______________________

XVI. COMMUNICATIONS

Describe the communications systems.

CHAPTER IV - PHYSICAL LAYOUT

A. INTRODUCTION

This chapter presents general information concerning the design of the substation physical arrangement. It describes various types of substations, illustrates typical layouts, and presents guidelines to be used during the detail design. Information concerning insulation, electrical clearances, bare conductors, substation bus design, and the application of mobile transformers and mobile substations is included.

B. LAYOUT CONSIDERATIONS

1. Initial Design Parameters

A careful analysis of basic parameters establishing the purposes and design criteria for the substation must precede the detail design. Much of this information can be found on the Substation Design Summary Form. In addition, circuit quantities, configurations, and ratings, system and equipment protective relay schemes, the necessity for specialized equipment (such as capacitor banks, current limiting reactors and neutral grounding devices), details of surge protection equipment, and requirements for direct stroke protection should be considered.

2. Selection of Switching Scheme

The power system as a whole must be considered when deciding the substation switching scheme. Future system growth based on long range forecasts may indicate the necessity for an economical, basic arrangement initially with possible future conversion to a more sophisticated scheme as the number of circuits increases. Important circuits may require additional protection or redundant supply. Equipment maintenance requirements may necessitate bypassing facilities to enable circuit operation during maintenance periods. Since the equipment that can be out of service for maintenance or during faults without sacrificing system operation depends upon alternate supplies and duplication of circuits, the flexibility of the switching scheme is often one of the most important selection criteria. Large substations with many circuits

handling great amounts of power must have high degrees of both flexibility and reliability to continue service without interruption during the most undesirable conditions. Since flexibility and reliability are directly proportional to cost, the ultimate configuration must be the result of a compromise.

3. Substation Expansion

Frequently, after initial substation construction, requirements change, and plans for the ultimate capabilities of the substation are altered. As a result, expansion of the substation facilities may deviate from the anticipated initial plan. To accommodate unforeseen future system modifications, the flexibility of the arrangement should be considered. Since a typical substation can be expected to continue in service for an indefinite time, maintaining maximum flexibility throughout each stage of expansion will ensure the least costly and most efficient use of the facilities during the service period.

To facilitate future expansion, the initial design should be arranged to accommodate all requirements of a current long range system forecast. The site should be as large as practical to allow for future development. Large areas more readily allow for changes in the basic substation configuration and switching scheme should future conditions so dictate. At least one and preferably both ends of all major buses should be left open for future expansion. When a basic initial arrangement is planned, placement of equipment should consider future expansion of the substation into a more complex, reliable and flexible configuration. Frequently, additional switches, switch stands, and bus supports are installed initially to facilitate future expansion.

4. Substation Profile

The profile of substation structures and equipment has become an increasingly important aspect to consider in substation layout. In the past, large lattice and box type structures supporting overhead strain buses were commonly used. Conventional high profile construction is still used somewhat today, particularly for low voltage distribution substations and in areas with natural environmental shielding. However, many substations currently being designed and constructed use low profile structures and rigid bus work.

Low profile construction generally uses lower structures with a minimum number of members for support. Larger pieces of equipment, such as power transformers and power circuit breakers, have become smaller over the years. Consequently, the substations are considered less obtrusive overall. The height limitations causing the use of low profile construction sometimes result in arrangements of increased area, particularly for the lower voltage levels. Generally, the advantages of easier equipment operation and maintenance due to reduced equipment sizes and effective locations make up for the expense of purchasing somewhat larger sites.

5. Underground Circuits

An effective method to improve substation appearance is to install circuits underground as they leave the substation. Low profile construction using lower structures with fewer support members lends itself toward the use of underground circuits. Undergrounding can similarly improve the appearance of substations with larger structures by reducing the size of some of the large supporting structures or eliminating them altogether.

6. Equipment Removal

Substation arrangements must include adequate space for the installation and possible removal of large equipment such as power transformers and power circuit breakers. Buses, particularly in low profile arrangements, even when at acceptable operating elevations, can block the removal of equipment. Consequently, it is important to consider equipment removal routes during the structure layout. Often the most desirable arrangement has the main buses at higher elevations than the buses and equipment in the substation bays. In this way, the main buses will not block the removal of equipment located in the substation interior.

Removable bus sections can also be provided to permit movement of large equipment. This, however, requires bus deenergization during the procedure.

Bay spacing must be carefully evaluated during layout to allow for removal of equipment. In multi-bay configurations, it is common to limit the number of bays to two before increasing the bay center-to-center spacing. This allows equipment to be removed from a bay to the side and

provides additional space for moving the equipment between this bay and an adjacent bay, as diagrammed in Figure IV-1.

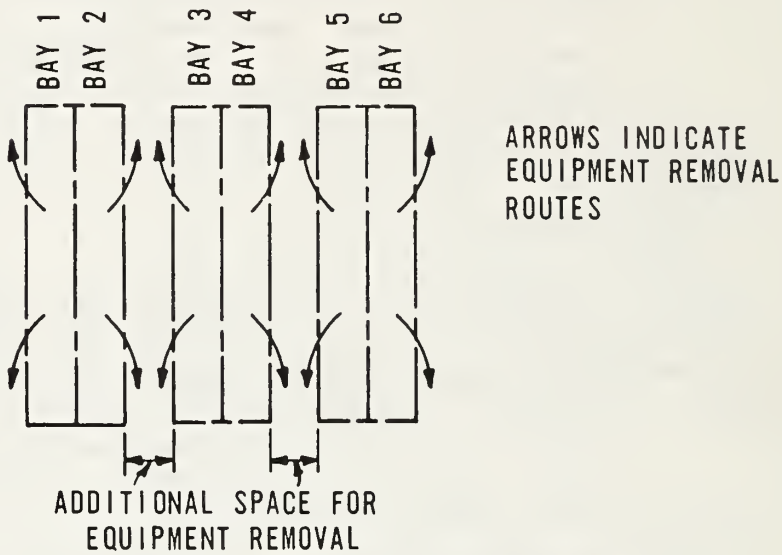


FIGURE IV-1 SUBSTATION PLAN VIEW SHOWING SPACE FOR EQUIPMENT REMOVAL

C. DISTRIBUTION SUBSTATIONS

1. Introduction

Distribution substations are usually characterized by voltages up to 138 kV on the primary side and 12.5Y/7.2kV or 24.9Y/14.4kV on the secondary side.

In recent years, the trend has been toward increasing system voltages. It is becoming more common to eliminate the intermediate transmission substations and directly reduce the transmission voltages to primary distribution levels. The distribution substations discussed are gen-

erally limited to the traditional type characterized by simple bus arrangements and minimal equipment. However, the arrangements can be expanded for use in larger distribution substations with higher voltages.

2. Basic Distribution Substation

Figure IV-2 is a one-line diagram for a basic distribution substation. Depending on the load being served, it is possible that initial construction may be limited to one distribution circuit.

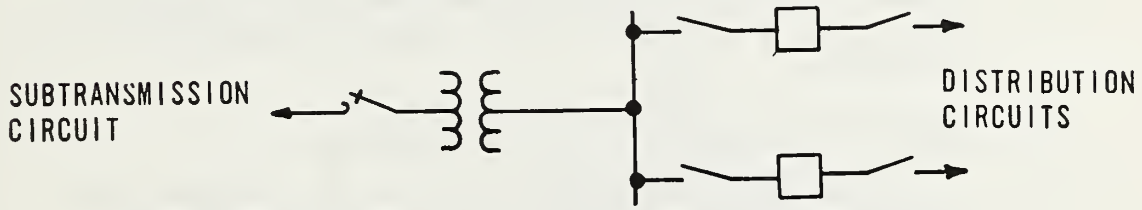


FIGURE IV-2 BASIC DISTRIBUTION SUBSTATION

The subtransmission circuit enters the substation through a primary disconnect switch used principally to isolate the substation from the subtransmission system for maintenance or when replacement of substation equipment is required. It is usually of the three pole, single throw, group operated type.

The power transformers commonly used in this application are two winding type and may be single or three phase units. In new substations and when replacing transformers or increasing transformer capacity, the trend has been

toward using three phase transformers. In configurations using single phase transformers, a fourth transformer should be added as a spare. Use of three phase transformers results in a neater and less cluttered arrangement. However, since failure of a three phase transformer necessitates loss of the substation, the overall design layout should provide facilities for the rapid installation of a mobile transformer or a mobile substation.

The two primary distribution feeders of the substation illustrated in Figure IV-2 are protected by either power circuit breakers or automatic circuit reclosers. Disconnect switches on both the source and load sides permit isolation during maintenance or other periods when complete de-energization is required. The switches can be either single pole, single throw, hook stick operated or three pole, single throw, group operated, depending on the arrangement.

3. Transformer Primary Protective Devices

To prevent equipment damage as a result of abnormal conditions such as transformer or low voltage bus faults, protective devices are generally provided on the primary side of the transformer. These devices may also serve as primary disconnects to enable isolation from the transmission system.

Several types of devices are available, including power fuses, circuit breakers, circuit switchers, and vacuum interrupters. Selection of the type of device is based on the voltage, short circuit conditions, and transformer capacity.

4. Voltage Regulation

To maintain voltage at a uniform level, voltage regulation equipment is usually required in rural distribution substations. The voltage can be regulated by using either feeder or bus regulation. Feeder regulation may be used in multi-circuit distribution substations, where the circuits are very diverse in load characteristics. With feeder regulation, the voltage of each distribution circuit can be individually maintained to conform to the load characteristics. Bus regulation may be used in rural distribution substations, where the distribution feeders have similar load characteristics. Bus voltage may be controlled by using power transformers with load tap

changing mechanisms, single or three phase voltage regulators, or switched capacitor banks.

To permit voltage regulator maintenance without feeder or bus de-energization, bypass facilities are provided as illustrated in Figure IV-3.

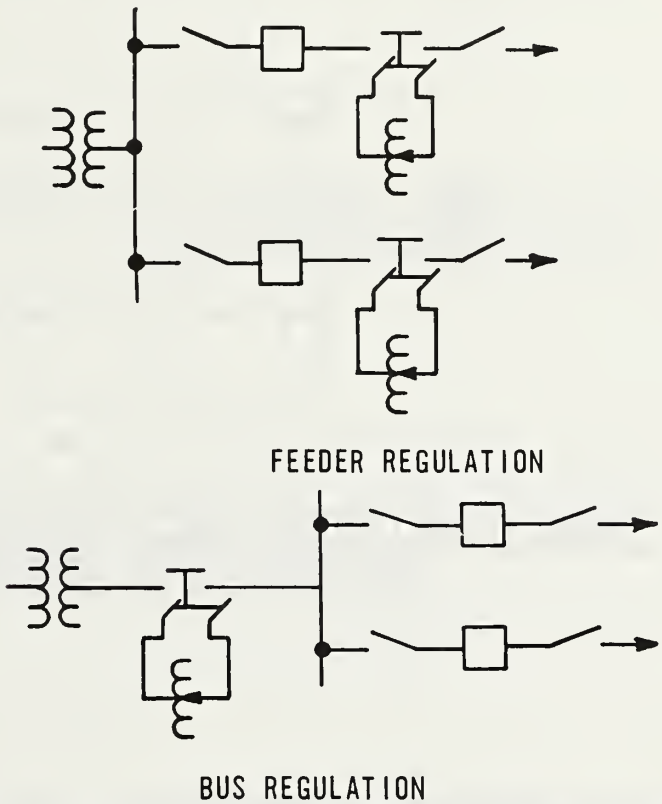


FIGURE IV-3 VOLTAGE REGULATOR BYPASS ARRANGEMENTS

The switches normally used for regulator bypassing automatically combine all switching operations and perform them in the correct operating sequence. Each combined switch can usually be installed in the same space as one single pole disconnect switch.

For a detailed discussion concerning the application of voltage regulators, See REA Bulletin 169-27.

5. Circuit Breaker/Recloser Bypass Facilities

Bypass facilities permit circuit breaker or recloser maintenance or repair without circuit de-energization. Figure IV-4 illustrates a typical bypass arrangement.

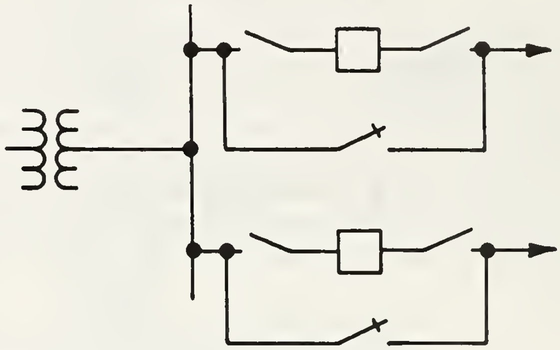


FIGURE IV-4 TYPICAL CIRCUIT BREAKER/ RECLOSER BYPASS ARRANGEMENT

The bypass switches usually consist of three independently operated hook stick switches, but a three pole group operated switch can also be used. In some applications, it may be desirable to combine some of the switches to facilitate installation. Figure IV-5 illustrates one possible configuration.

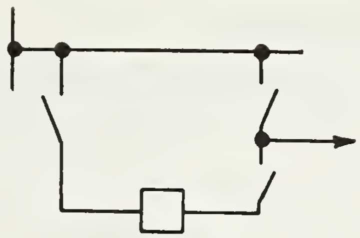


FIGURE IV-5 USE OF TANDEM SWITCHES FOR CIRCUIT BREAKER/RECLOSER BYPASSING

In this configuration, a tandem switch is used to combine the bypass switch and the load side disconnect switch onto a single switch base. The combined switch can be installed in nearly the same space as one single pole disconnect switch.

To provide circuit protection during bypassing, the bypass switch can be replaced by a fuse.

6. Surge Arresters

Transformers, regulators, and other substation equipment are particularly sensitive to transient overvoltages and are required by the National Electrical Safety Code to have surge protection.

For the highest degree of equipment protection, the arresters should be installed as close as practical to the equipment being protected. In most instances, power transformers can be furnished with surge arrester mounting brackets to facilitate installation. Separate arrester stands can also be used, or the arresters can be installed on adjacent switching structures. For voltage regulator applications, the surge arresters are normally installed directly on the regulator tanks.

When power transformers are protected by fuses, transformer surge arresters should be connected on the line

side of the fuses, as close as practical to the power transformers.

7. Enclosed Equipment

In certain applications, particularly when space is at a premium, use of switchgear, unit substations, or partially enclosed equipment should be considered. Switchgear is a name commonly used in referring to groupings of switching equipment contained in metal enclosures. All circuit breakers, metering and control equipment, and interconnecting buswork are contained inside the enclosures.

A unit substation consists of switchgear electrically and mechanically connected to at least one power transformer. Various arrangements of power transformers and switchgear equipment are available to suit individual requirements.

Use of switchgear, unit substations, and other types of enclosed equipment eliminates the need for extensive field construction, since most of the equipment is preassembled by the manufacturer or supplier. Depending on the configuration, the equipment may be shipped completely assembled or in sections to be connected together at the job site. Feeders are normally installed underground from the switchgear compartments.

Partial enclosure of some of the low voltage distribution equipment can be implemented to improve the appearance of the substation. The equipment can be furnished in modular form to facilitate installation. Interconnections between modules are usually underground.

D. TRANSMISSION SUBSTATIONS

1. Introduction

Transmission substations are usually characterized by primary and secondary voltages of 69 kV or higher. Since one transmission substation may supply several distribution substations and large loads, reliability of service and flexibility of operation are extremely important. Facilities normally allow equipment maintenance without circuit interruption. Multiple bus arrangements and extensive use of circuit breakers for switching provide added system flexibility.

2. <u>Basic Transmission Substation</u>

Figure IV-6 is a one-line diagram for a basic transmission substation. Depending on system requirements, initial substation construction may be limited to one power transformer and one subtransmission circuit.

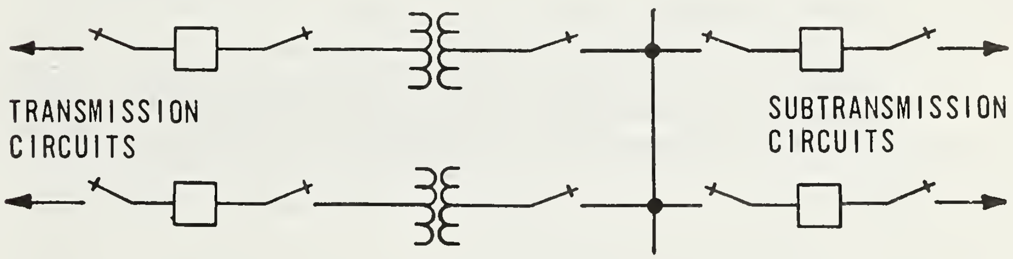


FIGURE IV-6 BASIC TRANSMISSION SUBSTATION

Power circuit breakers are included in the two transmission circuits to help prevent complete substation shutdown for line faults. The circuit breakers have disconnect switches on both source and load sides to permit isolation during maintenance or other periods requiring complete de-energization. These switches are normally of the three pole, single throw, group operated type, mounted on separate stands.

The power transformers commonly used are three phase autotransformers usually with tertiary windings. The disconnect switches on the low voltage sides of the power transformers allow de-energization of one transformer while maintaining service to both low voltage circuits from the other transformer.

The low voltage or secondary section of the substation illustrated in Figure IV-6 consists of two subtransmission feeders protected by power circuit breakers. Disconnect switches on both the source and load sides permit isolation during maintenance or other periods when complete de-energization is required. The switches are normally of the three pole, single throw, group operated type, but can be of the single pole, single throw, hook stick operated type, depending on the voltage and arrangement. Hook stick operated switches usually are not considered above 69 kV.

3. Circuit Breaker Bypass Facilities

Bypass facilities can be provided for the power circuit breakers to permit maintenance without circuit de-energization. Figure IV-7 illustrates a typical arrangement.

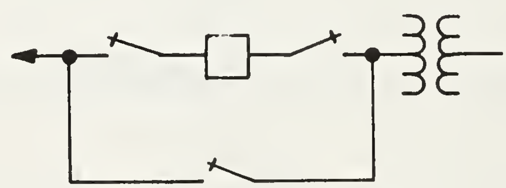


FIGURE IV-7 TYPICAL CIRCUIT BREAKER BYPASS ARRANGEMENT

The bypass facilities normally consist of three independent three pole, single throw, group operated switches. The circuit breaker disconnect switches may be of the

single pole, single throw, hook stick operated type, depending on system voltage and bus configuration.

In most cases bypassing circuit breakers removes normal relay protection since the circuit breaker current transformers are also removed from service. The overall protection scheme must be designed to provide for this situation.

4. Surge Arresters

Because of the desire for high reliability and the high cost of equipment replacement, surge arresters are installed in various positions in transmission substations. Since the power transformers are particularly sensitive to overvoltages, they normally have arresters on each phase of both the primary and secondary.

The highest degree of equipment protection occurs with the surge arresters located as close as possible to the equipment to be protected. Power transformers can usually be furnished with arrester mounting brackets adjacent to the transformer bushings.

Occasionally, surge arresters or other surge protective equipment are located at the line entrances and exits. In these instances, it is best to locate the arresters or other protective equipment on the line side of the substation equipment to be protected to limit the lightning and switching surges to acceptable levels as they enter the substation.

5. Carrier Equipment

Line traps, coupling capacitor voltage transformers and associated accessories are used when relaying or communications systems dictate use of carrier equipment for signal transmission to remote terminals. Normally, the line traps and coupling capacitor voltage transformers are installed on separate stands located near the circuit entrance positions in the substations. In some instances, the two pieces of equipment may be mounted on a common structure or stand, depending on the arrangement. The particular relaying and communications schemes being used on the circuit will dictate the number of phases containing line traps and coupling capacitor voltage transformers.

6. Voltage Transformers

Voltage transformers are used in conjunction with the circuit and equipment protection and metering schemes. They are normally mounted on individual or three position stands. Depending on the bus configuration and the relaying schemes, the voltage transformers may be positioned near the circuit entrance positions or adjacent to the buses.

It is usually desirable to provide a method for disconnecting the voltage transformers. One possible method is to install the primary connections to the appropriate buses by using disconnectable clamps. In arrangements using voltage transformers at the circuit positions, they can be positioned to allow de-energization by opening the power circuit breaker and the line disconnect switches.

7. Current Transformers

Current transformers used in both relaying and metering schemes can usually be located inside major equipment such as power circuit breakers and power transformers. These current transformers are normally multi-ratio bushing type and so do not require special mounting provisions. In some cases, separately mounted current transformers may be required, and they are usually installed on individual stands, located as required.

8. Grounding Switches

Manually operated grounding switches are frequently used to ground incoming circuits during maintenance or other out-of-service periods. These switches can be separately mounted or, as is usually the case, can be furnished as part of the circuit disconnect switches. The switches can then be interlocked in such a way as to prevent both from being closed simultaneously.

High speed grounding switches are sometimes used in power transformer protection schemes to initiate tripping of remote circuit breakers during transformer faults. As with manually operated grounding switches, high speed grounding switches can be separately mounted or can be furnished as part of group operated disconnect switches. High speed grounding switches are normally installed on one phase only.

E. SWITCHING SUBSTATIONS

1. Introduction

Switching substations do not change system voltage from one level to another and therefore do not contain power transformers. Switching substations usually operate at subtransmission or transmission voltage levels.

Depending on system voltage, the equipment types and characteristics used in switching substations are identical to those used in transmission substations.

2. Basic Switching Substation

Figure IV-8 is a one-line diagram for a basic switching substation with three terminals.

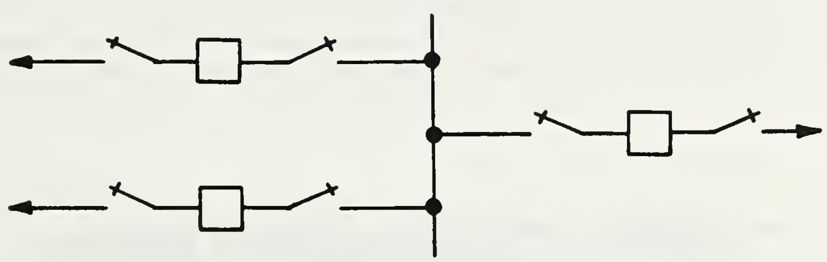


FIGURE IV-8 BASIC SWITCHING SUBSTATION

Power circuit breakers in the three circuits help prevent complete substation shutdown for line faults. The circuit breakers have disconnect switches on both source and load sides to permit isolation during maintenance or other periods requiring complete de-energization. Depending on substation voltage and bus configuration, the switches may be of the three pole, single throw, group operated type or of the single pole, single throw, hook stick operated type. Hook stick operated switches usually are not considered above 69 kV.

Bypass facilities can be provided to allow circuit breaker maintenance without de-energizing the circuit. Figure IV-9 illustrates a typical bypass arrangement.

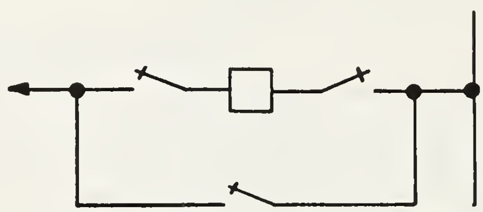


FIGURE IV-9 TYPICAL CIRCUIT BREAKER BYPASS ARRANGEMENT

The bypass facilities may consist of three independent three pole, single throw, group operated switches; single pole, single throw, hook stick operated switches; or a combination of the two types, depending on system voltage and bus configuration.

3. Surge Arresters

Surge arresters or other surge protective equipment may be installed either on the line positions or on the substation buses to protect against excessive lightning or switching surges.

A comparison of the costs of the surge protection equipment to the frequency and extent of possible equipment damage can be evaluated to determine the desirability of the protective equipment. Possible circuit or substation outages as a result of the unprotected surges should be considered.

F. TYPICAL BUS CONFIGURATIONS

1. General

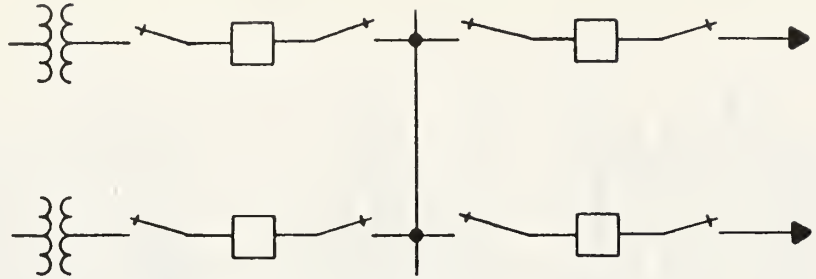
The typical bus configurations may be used for distribution, transmission or switching substations at voltages up to 230 kV. Details will vary depending on the type and voltage(s) of the substations. The physical size, type and arrangement of major equipment, such as power transformers, power circuit breakers and switches, may cause variance in the layouts to suit individual requirements. Portions of different layouts may be combined, as required, to achieve desired configurations.

It is important that the Engineer's plans remain as flexible as possible during substation layout to allow for unforeseen difficulties as his designs progress. He should coordinate his activities with the equipment manufacturers to ensure that each design detail reflects the actual equipment to be used.

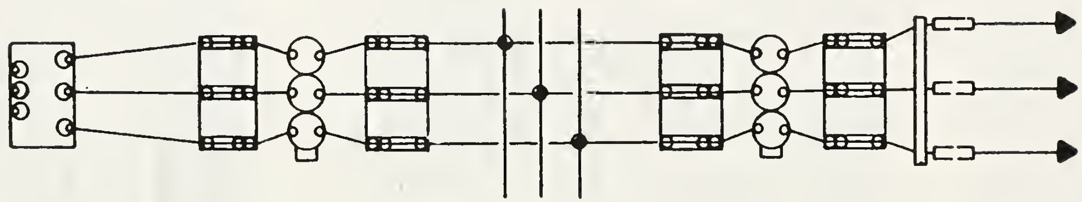
2. Single Bus

A single bus configuration consists of one main bus that is energized at all times and to which all circuits are connected. This arrangement is the simplest, but provides the least amount of system reliability. Bus faults or failure of circuit breakers to operate under fault conditions results in complete loss of the substation. The single bus configuration can be constructed by using either low or high profile type structures. Figure IV-10 illustrates the single bus arrangement with low profile structures and presents a neat, orderly plan. The high profile design, shown in Figure IV-11, accomplishes the same purpose and may not require as large a site for a given system voltage.

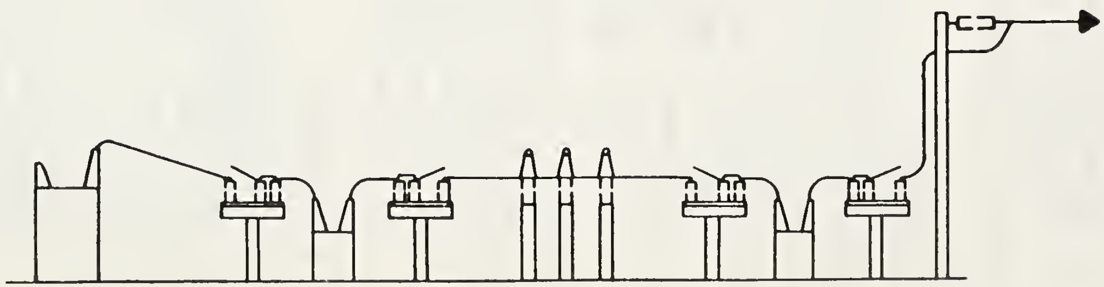
The single bus arrangement is not recommended without circuit breaker bypass facilities that permit circuit



TYPICAL ONE LINE DIAGRAM

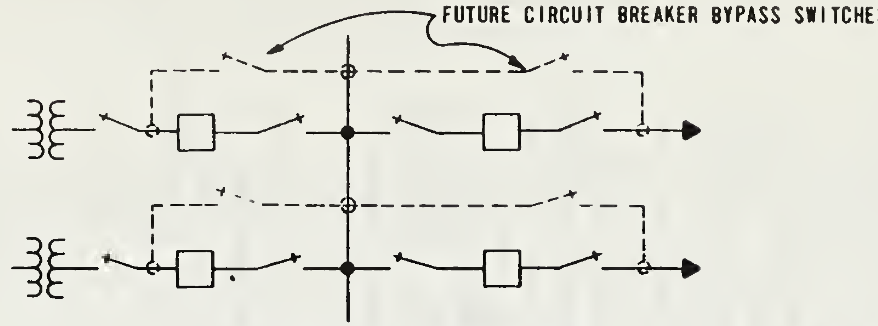


PLAN VIEW-TYPICAL BAY

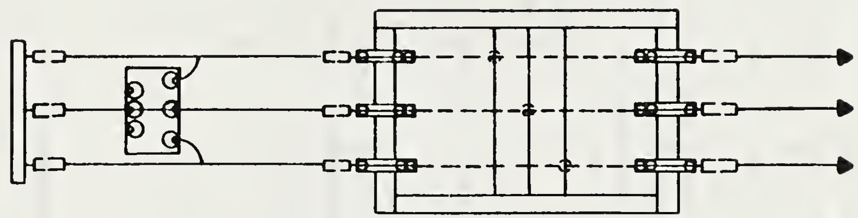


ELEVATION-TYPICAL BAY

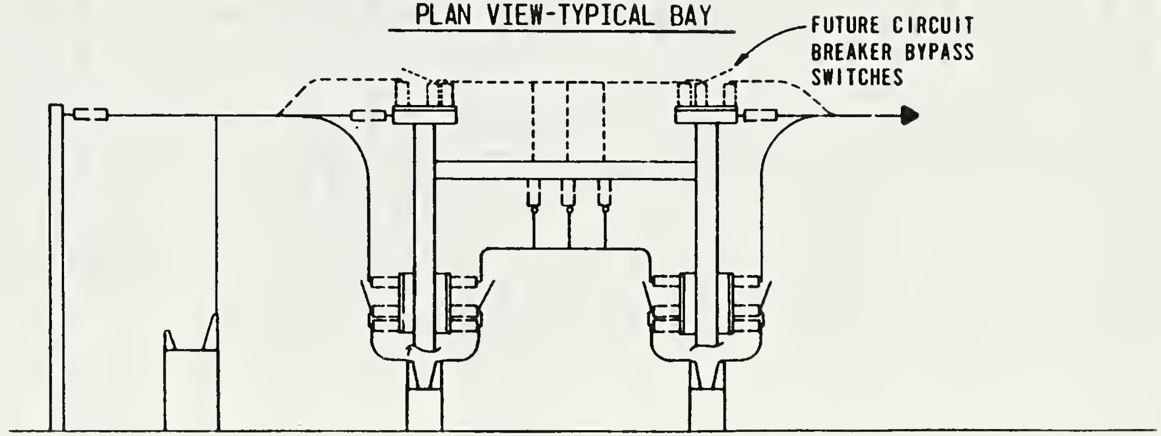
FIGURE IV-10 SINGLE BUS-LOW PROFILE



TYPICAL ONE LINE DIAGRAM



PLAN VIEW-TYPICAL BAY



ELEVATION-TYPICAL BAY

FIGURE IV-11 SINGLE BUS-HIGH PROFILE

breaker maintenance while maintaining circuit operation. The high profile configuration can easily be modified to provide this feature by installing group operated switches and the associated buswork and connections in the positions shown in Figure IV-11. This arrangement, however, results in loss of overcurrent protection for the circuit except by remote circuit breakers during the bypassing operations. A fault occurring on the line with the breaker bypassed would result in complete substation shutdown. The low profile arrangement does not allow for future addition of this type of bypassing equipment. Consequently, in both low profile and some high profile substations, the bypass facilities can be installed outside the substation. Switches can be provided that, when closed, parallel two lines to enable one circuit breaker to be removed from service. The other breaker then protects both circuits. If this bypassing method is used, the equipment associated with both circuits must be capable of carrying the total load of both circuits. If the load is greater than the equipment capability, the load should be reduced. This method of circuit breaker bypassing may be more desirable in high profile arrangements than that shown in Figure IV-11 for lines where frequent or lengthy equipment maintenance is expected.

The high profile configuration shown in Figure IV-11 is generally limited to distribution and subtransmission voltage levels. At transmission voltage levels, independent structures and strain bus interconnections are usually used.

Advantages

1. Lowest cost
2. Small land area required
3. Easily expandable
4. Simple in concept and operation
5. Relatively simple for the application of protective relaying

Disadvantages

1. High profile arrangement equipped with circuit breaker bypass facilities does not provide for circuit protection when bypass facilities are being used inside the substation

2. Lowest reliability

3. Failure of a circuit breaker or a bus fault causes loss of the entire substation

4. Maintenance switching can complicate and disable some of the protective relay scheme and overall relay correlation

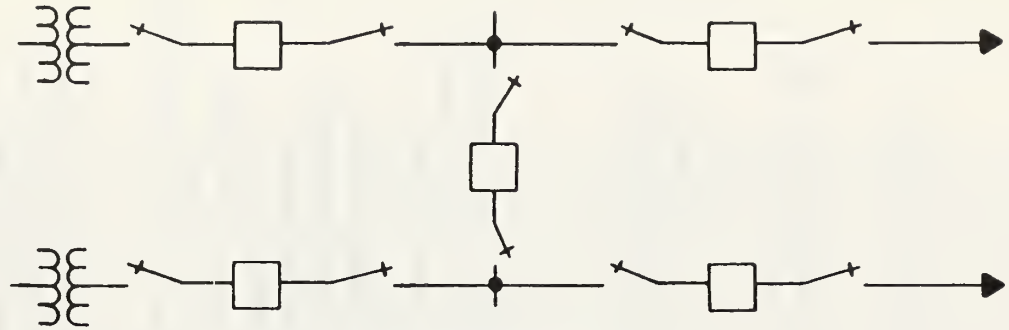
5. Maintenance at the upper elevations of high profile arrangements necessitates de-energization or protection of the lower equipment

3. Sectionalized Bus

An extension of the single bus configuration is the sectionalized bus arrangement shown in Figure IV-12. This arrangement is basically two or more single bus schemes, each tied together with bus sectionalizing breakers. The sectionalizing breakers may be operated normally open or closed, depending on system requirements. In this arrangement, a bus fault or breaker failure causes only the affected bus section to be removed from service and thus eliminates total substation shutdown. Usually, the fault can be isolated and nonfaulted portions of the system restored to service easier and faster because of the increased flexibility of the arrangement.

Physically, the equipment can be organized similar to that shown in Figures IV-10 and IV-11 for the single bus arrangement. The sectionalizing breakers and their associated isolation switches are located in line with the main bus. In the high profile configuration, it is usually desirable to provide a separate bay for the sectionalizing breakers and switches to facilitate maintenance and removal.

The arrangement of lines and transformers in a sectionalized bus arrangement is dependent upon system operating criteria. They should be so arranged to prevent outage of lines or other circuits dependent on each other. This



TYPICAL ONE LINE DIAGRAM

(SEE FIGURES IV-10 & IV-11
FOR TYPICAL ARRANGEMENTS)

FIGURE IV-12 SECTIONALIZED BUS

can be accomplished by positioning the interrelated circuits on different bus sections to eliminate concurrent shutdown. A thorough analysis of all possible operational contingencies identifying any undesirable conditions should precede the final determination of circuit grouping.

Bypassing arrangements for the sectionalized bus configuration can be provided as explained for the single bus scheme.

Advantages

1. Flexible operation

2. Higher reliability than single bus scheme

3. Bus sections can be isolated for maintenance

4. Only part of the substation is lost for a breaker failure or a bus fault

Disadvantages

1. Higher cost than single bus scheme

2. Additional circuit breakers required for sectionalizing

3. Sectionalizing may cause interruption of nonfaulted circuits

4. Main and Transfer Bus

A main and transfer bus configuration consists of two independent buses, one of which, the main bus, is normally energized. Under normal operating conditions, all incoming and outgoing circuits are fed from the main bus through their associated circuit breakers and switches. If it becomes necessary to remove a circuit breaker from service for maintenance or repairs, the integrity of circuit operation can be maintained through use of the bypass and bus tie equipment. The bypass switch for the circuit breaker to be isolated is closed, the bus tie breaker and its isolation switches are closed, and the bypassed breaker and its isolation switches are opened to remove the breaker from service. The circuit is then protected by the bus tie breaker.

Figure IV-13 illustrates a main and transfer bus configuration in a low profile arrangement. For comparison, Figure IV-14 shows the same switching scheme with high profile box-type structures. With the box-type structure arrangement, two circuit positions can be accommodated per equipment bay. However, with the low profile arrangement, each circuit requires its own bay and, as a result, somewhat more land area may be required. When the low profile configuration is used, equipment bays should be limited in width to a maximum of two bays before the bay to bay centerline spacing is increased to accommodate circuit breaker maintenance and removal. Without the additional space, these tasks can become very difficult.

The high profile, box-type structure arrangement shown in Figure IV-14 can accommodate multiple circuits in a relatively small area. The configuration is particularly suitable in environmentally shielded or otherwise isolated locations, where only a limited substation site is available. This arrangement is generally limited to distribution and subtransmission voltage levels. At transmission voltage levels, independent structures and strain bus interconnections can be used.

Advantages

1. Accommodates circuit breaker maintenance while maintaining service and line protection

2. Reasonable in cost

3. Fairly small land area required

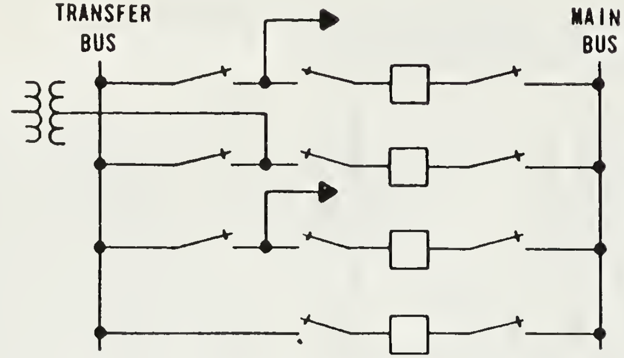
4. Easily expandable

Disadvantages

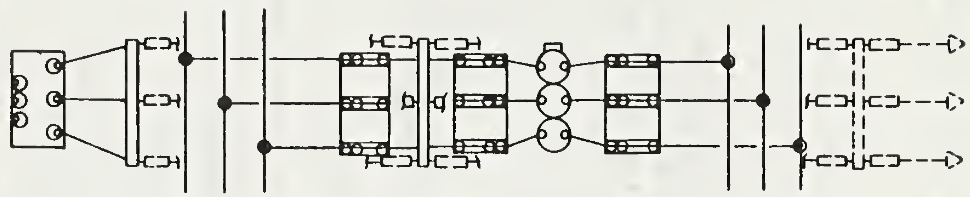
1. Additional circuit breaker required for bus tie

2. Since the bus tie breaker must be able to be substituted for any line breaker, its associated relaying may be somewhat complicated

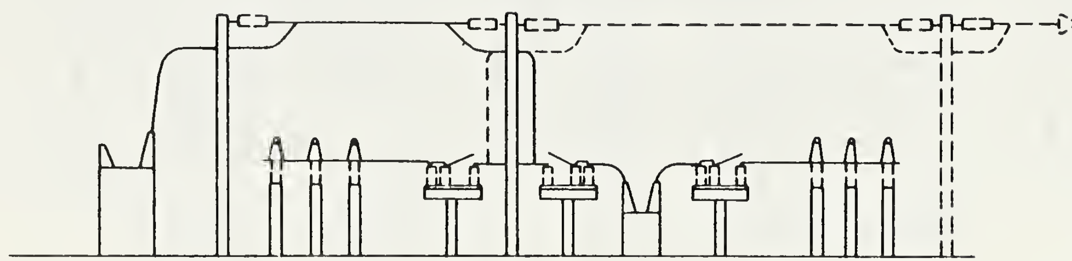
3. Failure of a circuit breaker or a bus fault causes loss of the entire substation



TYPICAL ONE LINE DIAGRAM

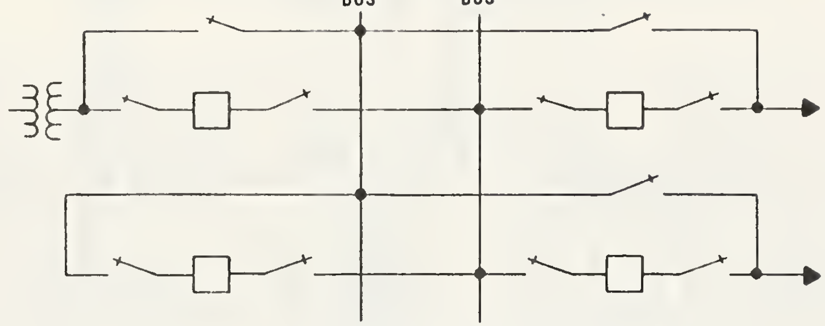


PLAN VIEW-TYPICAL BAY

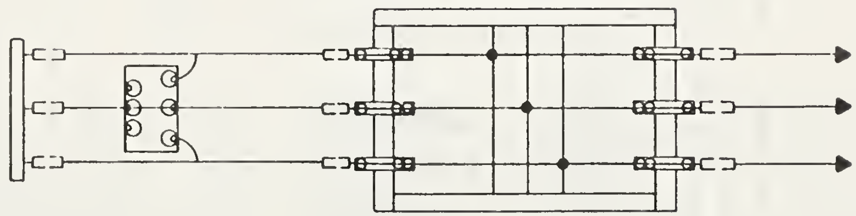


ELEVATION TYPICAL BAY

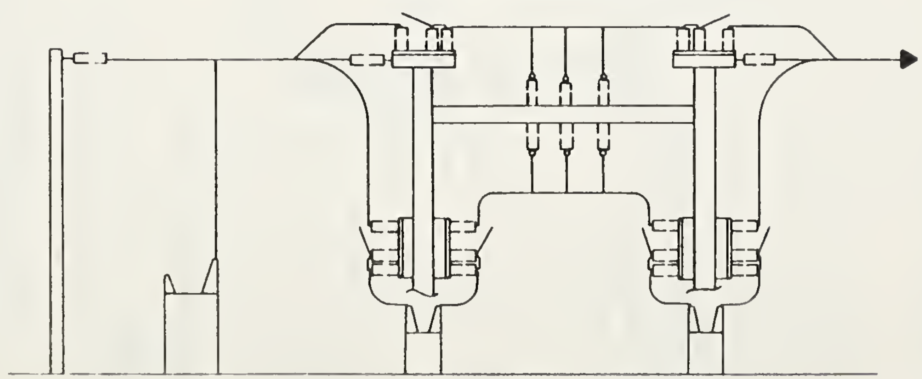
FIGURE IV-13 MAIN AND TRANSFER BUS-LOW PROFILE



TYPICAL ONE LINE DIAGRAM



PLAN VIEW-TYPICAL BAY



ELEVATION-TYPICAL BAY

FIGURE IV-14 MAIN AND TRANSFER BUS-HIGH PROFILE

4. Somewhat complicated switching required to remove a circuit breaker from service for maintenance

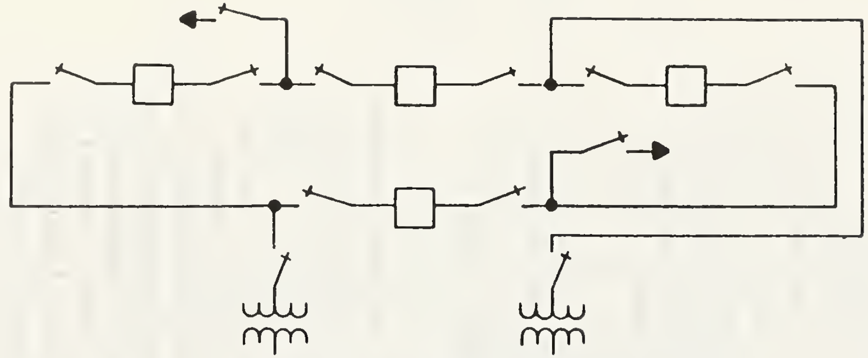
5. Ring Bus

A ring bus configuration is an extension of the sectionalized bus arrangement and is accomplished by interconnecting the two open ends of the buses through another sectionalizing breaker. This results in a closed loop or ring with each bus section separated by a circuit breaker. For maximum reliability and operational flexibility, each section should supply only one circuit.

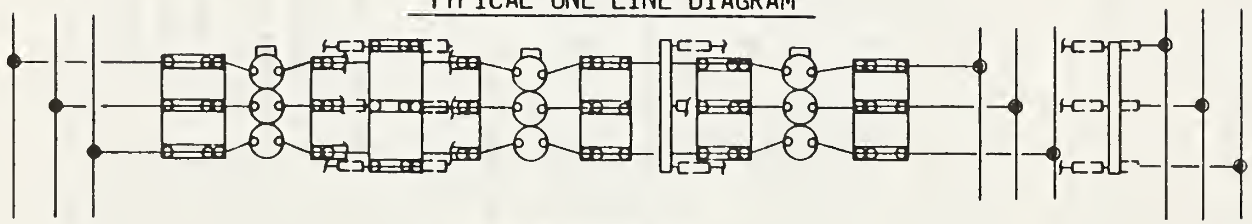
In this arrangement, as with the sectionalized bus configuration, only limited bus sections and circuits are removed from service because of line or bus faults or circuit breaker failure. For a line or bus fault, the two circuit breakers on the sides of the affected bus section open to isolate the fault. The remaining circuits operate without interruption. For a breaker failure, the two breakers on the sides of the affected breaker open to isolate the failed breaker and remove two bus sections from service.

The ring bus arrangement provides for circuit breaker maintenance, since any breaker can normally be removed from service without interruption of service to any circuits. As a result, separate circuit breaker bypass facilities are not required.

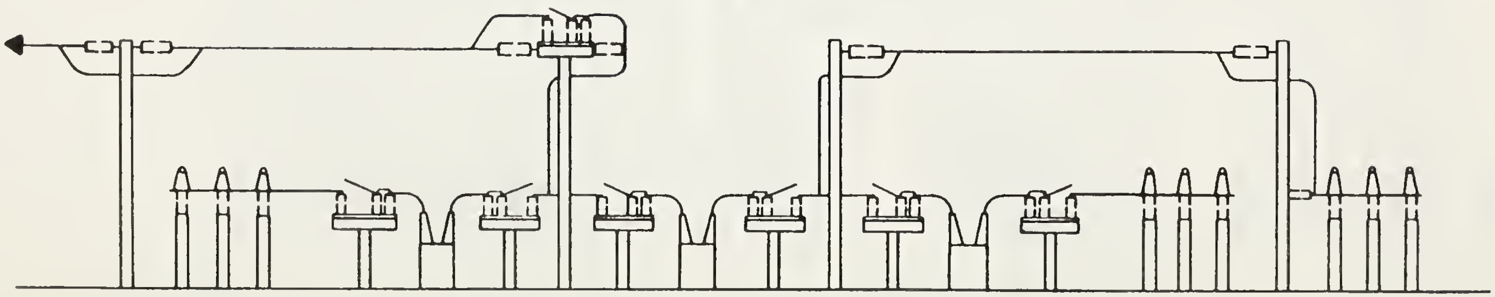
A number of equipment arrangements may be used to provide a ring bus configuration, depending on anticipated substation expansion and possible system modifications. Figure IV-15 illustrates a typical ring bus configuration. The arrangement shows four circuit positions, which is a practical maximum for a ring bus configuration. Rather than expanding the ring bus to accommodate additional circuits, other more flexible and reliable configurations, such as the breaker-and-a-half scheme, can be adopted. The ring bus arrangement shown in Figure IV-15 is readily adaptable in the future to a breaker-and-a-half configuration as shown in Figure IV-16. However, the relay and control panels must be carefully planned to be modified later for breaker-and-a-half operation.



TYPICAL ONE LINE DIAGRAM



TYPICAL PLAN VIEW



TYPICAL ELEVATION

FIGURE IV-15 RING BUS

Bay centerline spacing should be carefully planned to permit equipment maintenance and removal.

Advantages

1. Flexible operation

2. High reliability

3. Can isolate bus sections and circuit breakers for maintenance without disrupting circuit operation

4. Double feed to each circuit

5. No main buses

6. Expandable to breaker-and-a-half configuration

Disadvantages

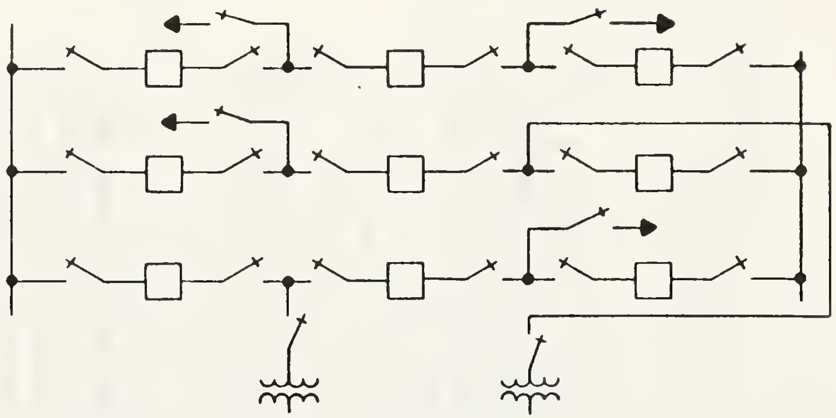
1. Ring may be split by faults on two circuits or a fault during breaker maintenance to leave possibly undesirable circuit combinations (supply/load) on the remaining bus sections. Some consider this, however, to be a second contingency factor.

2. Each circuit must have its own potential source for relaying

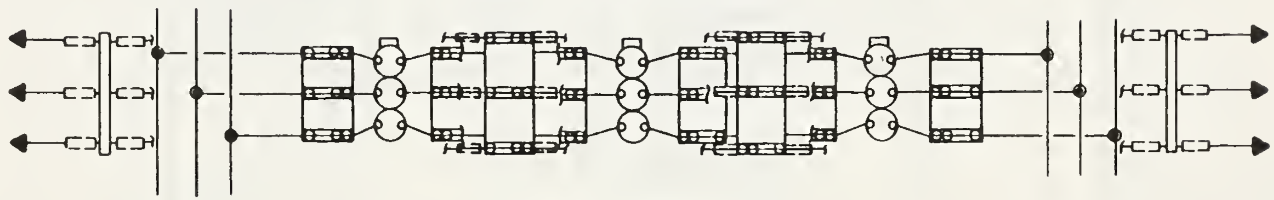
3. Usually limited to a maximum of four circuit positions

6. Breaker-And-A-Half

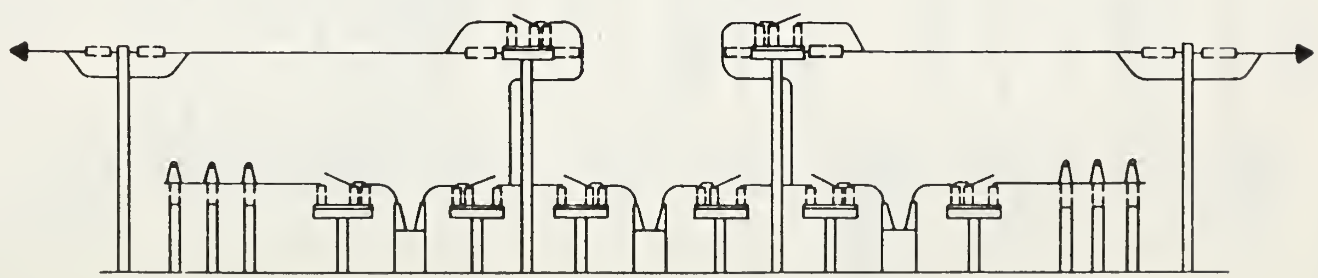
The breaker-and-a-half configuration consists of two main buses, each normally energized. Electrically connected between the buses are three circuit breakers and, between each two breakers, a circuit as diagrammed in Figure IV-16. In this arrangement, three circuit breakers are used for two independent circuits; hence, each circuit shares the common center circuit breaker, so there are one-and-a-half circuit breakers per circuit.



TYPICAL ONE LINE DIAGRAM



PLAN VIEW-TYPICAL BAY



ELEVATION-TYPICAL BAY

FIGURE IV-16 BREAKER-AND-A-HALF

The breaker-and-a-half configuration provides for circuit breaker maintenance, since any breaker can be removed from service without interrupting any circuits. Additionally, faults on either of the main buses cause no circuit interruptions. Failure of a circuit breaker results in the loss of two circuits if a common breaker fails and only one circuit if an outside breaker fails.

A typical bus configuration for a breaker-and-a-half arrangement is shown in Figure IV-16. This is the same basic equipment assemblage as described for the ring bus scheme.

Frequently, substations are initially constructed with a ring bus arrangement and ultimately expanded into a breaker-and-a-half configuration for the additional flexibility and reliability required with the additional circuits.

Bay centerline spacing should be carefully planned to permit equipment maintenance and removal.

<u>Advantages</u>

1. Flexible operation

2. High reliability

3. Can isolate either main bus for maintenance without disrupting service

4. Can isolate any circuit breaker for maintenance without disrupting service

5. Double feed to each circuit

6. Bus fault does not interrupt service to any circuits

7. All switching done with circuit breakers

<u>Disadvantages</u>

1. 1-1/2 breakers required per circuit

2. Involved relaying, since center breaker must respond to faults of either of its associated circuits

7. Double Breaker-Double Bus

The double breaker-double bus configuration consists of two main buses each normally energized. Electrically connected between the buses are two circuit breakers and, between the breakers, a circuit, as diagrammed in Figure IV-17. Two circuit breakers are required for each circuit.

In the double breaker-double bus configuration, any circuit breaker can be removed from service without interruption of any circuits. Faults on either of the main buses cause no circuit interruptions. Circuit breaker failure results in the loss of only one circuit.

A typical bus configuration for a double breaker-double bus arrangement is shown in Figure IV-17.

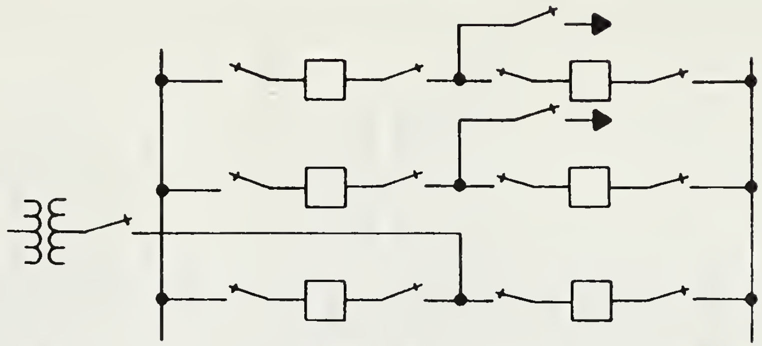
Use of the double breaker-double bus configuration is usually limited to large generating stations because of the high cost. The additional reliability afforded by this arrangement over the breaker-and-a-half scheme usually cannot be justified for conventional transmission or distribution substations.

Advantages

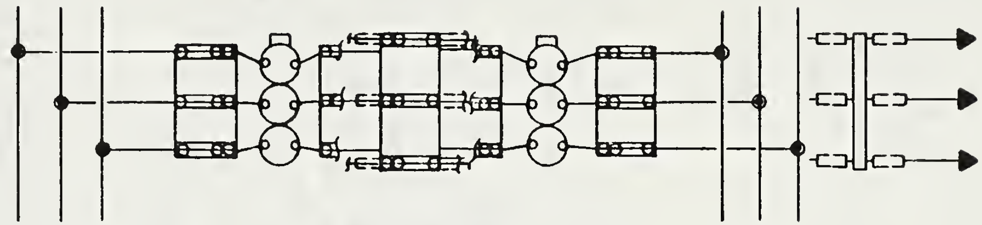
1. Flexible operation
2. Very high reliability
3. Can isolate either main bus for maintenance without disrupting service
4. Can isolate any circuit breaker for maintenance without disrupting service
5. Double feed to each circuit
6. Bus fault does not interrupt service to any circuits
7. Only one circuit lost for breaker failure
8. All switching done with circuit breakers

Disadvantages

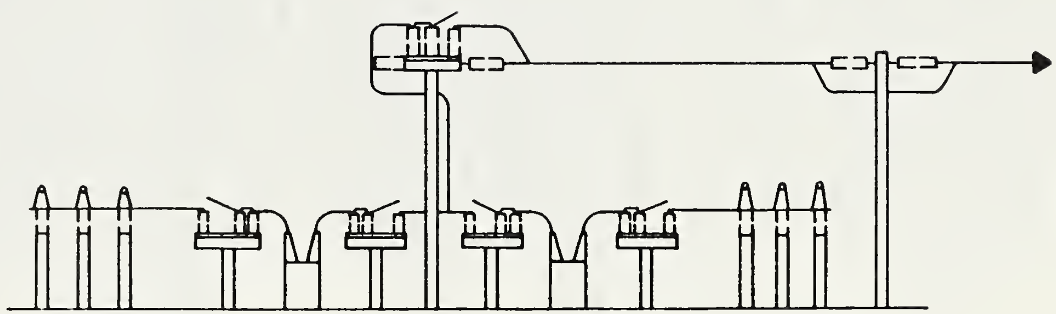
1. High cost
2. Two circuit breakers required for each circuit



TYPICAL ONE LINE DIAGRAM



PLAN VIEW-TYPICAL BAY



ELEVATION-TYPICAL BAY

FIGURE IV-17 DOUBLE BREAKER-DOUBLE BUS

8. Relative Switching Scheme Costs

The selection of a substation switching scheme is the result of the evaluation of many factors, including such intangibles as personal preference and judgment. Whatever arrangement is finally selected should meet all known or anticipated requirements, such as operating and maintenance criteria, future expansion, and reliability.

To assist in the evaluation, the following table provides a reasonable measure for the basis of economic comparison.

Switching Scheme	Approximate Relative Cost Comparison
Single Bus	100%
Sectionalized Bus	122%
Main and Transfer Bus	143%
Ring Bus	114%
Breaker-and-a-Half	158%
Double Breaker-Double Bus	214%

The comparison is based on four-circuit low profile arrangements with power circuit breakers in all circuits. Power transformer costs are not included. In schemes utilizing other protective devices or different circuit quantities, the relative costs may vary from those listed. It is recommended that detailed construction estimates be prepared for all schemes under consideration.

G. PROTECTION OF SUBSTATION INSULATION

1. General

Substation electrical equipment is subject to abnormal conditions as a result of direct lightning strokes, lightning surges, switching surges, and faults on the system. These abnormal conditions can cause overvoltages that may result in equipment flashover or insulation failure. To prevent equipment damage and/or system shutdown from overvoltages, protective devices are used to limit the overvoltages to reasonable levels. Application of these devices is usually a compromise between the costs of the devices and the degree of protection desired.

The protection provided for substations and substation equipment can be broken into two main parts - surge protection, employed to protect the equipment from damaging overvoltages caused by lightning surges, switching surges, and system faults; and direct stroke protection, employed to protect the equipment from direct lightning strokes.

2. Surge Protection

Surge arresters are used to protect equipment against overvoltages caused by incoming surges. The arresters function by discharging surge current to the ground system and then interrupt the current to prevent flow of normal power frequency follow current to ground. A detailed discussion concerning the application and selection of surge arresters can be found in Chapter V.

3. Direct Stroke Protection

a. Shielding

Since the effects of a direct lightning stroke to an unshielded substation can be devastating, it is recommended that some form of direct stroke protection be provided. Direct stroke protection normally consists of shielding the substation equipment by using lightning masts, overhead shield wires or a combination of these devices. The types and arrangements of protective schemes used are based on the size and configuration of the substation equipment.

b. Overhead Shield Wires

Overhead shield wires are often used to provide direct stroke protection. The shield wires can be supported by the circuit pull-off structures, if conveniently located, to extend over the substation. Since these shield wires are located above substation buses and equipment, breakage could result in outage of and/or damage to equipment. To minimize possible breakage, the overhead shield wire systems are constructed from high quality, high strength materials as listed in REA Bulletin 43-5, Item y. Shield wires should be limited to a maximum design tension of 8900 newtons (2000 pounds) per conductor under the appropriate loading conditions as defined in the National Electrical Safety Code. This tension is based only on wire strength and must be coordinated with support

structure design. Lower tensions may be required for certain applications, depending on the capabilities of the support structures. Sag must be considered to ensure adequate clearance from energized equipment.

A complete overhead shield wire system should include protection for overhead circuits entering or leaving the substation. In areas not employing transmission line shielding, substation shield wire systems should be extended at least 805 meters (one-half mile) away from the substation to limit the exposure of the phase conductors to direct strokes near the substation. Strokes occurring on the circuits beyond the shielding will usually be attenuated enough by the time they reach the substation to be discharged successfully by the surge arresters without causing equipment damage. For adequate protection, the circuit shield wire systems should be directly connected to the substation shield wire system.

c. Shielding Masts

Shielding masts can be used for nearly all types of substations to provide protection against direct lightning strokes. They are particularly useful in large substations and those of low profile design. Shielding masts can be guyed or self-supporting steel poles or lattice type towers and are usually made of steel. Other materials, such as precast concrete or aluminum, can also be used.

In some instances, shielding masts can also be used to provide support for substation lighting equipment.

d. Zone of Protection

The zone of protection of a shielding system is the volume of space inside which equipment is considered adequately protected by the system. A shielding system allowing no more than 0.1 percent of the total predicted number of lightning strokes to terminate on the protected equipment is considered adequate for most situations. The shaded areas in Figure IV-18 illustrate the zones of protection afforded by single and double mast or shield wire systems. For a single mast, the zone of protection consists of a cone. For a single shield wire, the zone of protection is a wedge. When two or more masts or shield wires are

used, the zones of protection of each overlap to provide complete coverage. The table shown in Figure IV-18 lists the ranges of angles that have been used for various shielding systems.

ANGLE	RANGE	RECOMMENDED
A	20° TO 60°	30°
B	40° TO 60°	45°

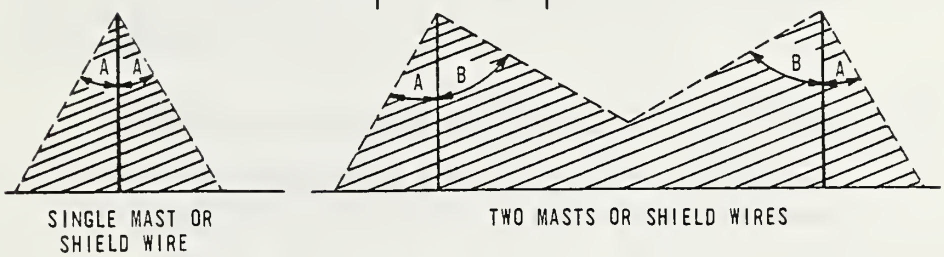


FIGURE IV-18 ZONES OF PROTECTION FOR MASTS AND SHIELD WIRES

e. Shielding System Grounding

A shielding system cannot effectively protect substation equipment unless adequately grounded. Multiple low impedance connections from the shielding system to the substation ground grid are essential. It is beneficial to use at least two separate connections to ensure continuity and reliability. Whenever nonconducting masts or supports are used, separate ground cables to establish a direct connection should be installed from the shield system to the substation ground system.

H. SUBSTATION INSULATORS

1. Outdoor Apparatus Insulators

a. Types

Outdoor apparatus insulators are used primarily to support rigid buswork and other electrical equipment operated above ground potential. Apparatus insulators are normally manufactured from electrical grade wet-process porcelain and are available in two major types: cap and pin type and post type. Other types are also available from some insulator manufacturers.

b. Cap and Pin Type Outdoor Apparatus Insulators

Cap and pin type apparatus insulators are the original insulator type used in substation construction.

Cap and pin insulators are usually manufactured with at least two shells of different diameter cemented together to achieve the required electrical characteristics. The spacing and configuration of the shells generally prevent flashover caused by dripping water. The wide shell spacing also permits natural cleaning of the exposed surfaces, to minimize the build-up of surface contamination.

The wide shells of the insulators are susceptible to damage from flashovers and other causes. Since the insulators rely on the large shell diameters to provide their electrical characteristics, breakage or other damage to the shells can greatly reduce the electrical characteristics and possibly cause permanent insulator failure.

Cap and pin insulators are available in two types - stacking and nonstacking. Single nonstacking insulators are normally used through nominal voltages of 46 kV (250 kV BIL). At nominal voltages of 69 kV (350 kV BIL) and above, stacking type insulators are used.

Cap and pin apparatus insulators are manufactured and tested in accordance with the following standards:

ANSI C29.1	Test Methods for Electrical Power Insulators

ANSI C29.8	Standard for Wet-Process Porcelain Insulators (Apparatus, Cap and Pin Type)
NEMA HV1	High Voltage Insulators

c. Post Type Outdoor Apparatus Insulators

Post type apparatus insulators are the type most often used today for new substation construction. The uniform profile and smaller diameter enhance the insulator appearance.

Post type apparatus insulators are generally manufactured from one piece of electrical grade wet-process porcelain formed with a number of vertical skirts to achieve the required electrical characteristics. End caps for mounting the insulators are cemented to the porcelain. Since the insulators are manufactured with a minimum number of joints, they are more rigid than the cap and pin type and, consequently, have reduced deflections.

The short skirts of post insulators make them less susceptible to damage from flashovers than the cap and pin type. Even if some of the skirts are damaged, insulation integrity is usually maintained, since the dry arcing distances are not greatly affected.

Post type insulators are available in two types - stacking and nonstacking. Single nonstacking insulators are normally used through nominal voltages of 69 kV (350 kV BIL). At nominal voltages of 115 kV (550 kV BIL) and above, stacking type insulators are used.

Since post type insulators are available in different colors, preferences should be made known in advance of purchasing.

Post type apparatus insulators are manufactured and tested in accordance with the following standards:

ANSI C29.1	Test Methods for Electrical Power Insulators
ANSI C29.9	Standard for Wet-Process Porcelain Insulators (Apparatus, Post Type)

d. BIL (Impulse Withstand) Ratings of Outdoor Apparatus Insulators*

Apparatus insulators are available with BIL (impulse withstand) ratings as listed in Table IV-1. Use of the BIL's for the nominal system voltages listed will normally ensure adequate coordination with protective devices and insulation systems of other equipment for most operating conditions. In areas of extremely high contamination, it may be desirable to increase the insulator BIL to levels higher than listed.

*For apparatus insulators, impulse withstand voltages are commonly referred to as BIL's.

TABLE 1V-1

Apparatus Insulator BIL (Impulse Withstand) Ratings for Nominal System Voltage

Nominal System Voltage kV	Apparatus Insulator BIL (Impulse Withstand) kV
14.4	110
23	150
34.5	200
46	250
69	350
115	550
138	650
161	750
230	900
230	1050

According to ANSI C37.30, "Definitions and Requirements for High-Voltage Air Switches, Insulators, and Bus Supports," equipment that depends on air for its insulating medium will have a lower dielectric strength when operated at higher altitudes than when operating at lower altitudes. For altitudes above 1000 meters (3300 feet), the correction factors shown in Table IV-2 should be applied to reduce the insulator BIL's.

TABLE IV-2

Altitude Correction Factors

Altitude Meters (feet)	Correction Factors to Be Applied to BIL
1000 (3300)	1.00
1200 (4000)	0.98
1500 (5000)	0.95
1800 (6000)	0.92
2100 (7000)	0.89
2400 (8000)	0.86
2700 (9000)	0.83
3000 (10,000)	0.80
3600 (12,000)	0.75
4200 (14,000)	0.70
4800 (16,000)	0.65
5400 (18,000)	0.61
6000 (20,000)	0.56

e. Leakage Distance of Outdoor Apparatus Insulators

Cap and pin and post type apparatus insulators depend on the insulating material contours to achieve the required leakage distances. Breakage of a shell on a cap and pin type can greatly reduce the leakage distance and possibly cause insulator flashover. Skirt breakage on a post type usually will not cause insulator flashover, since a much smaller percentage of the total leakage distance is destroyed compared to the cap and pin type. Post type apparatus insulators generally have longer leakage distances than their counterparts, particularly at the lower BIL's.

In areas of high contamination it is usually desirable to utilize insulators with either longer than standard leakage distances or higher BIL's to prevent electrical breakdown from surface contamination. Application of insulators in unusual situations such as high contamination can sometimes best be accomplished by referring the problem to the insulator manufacturers for recommendations.

f. Mechanical Strength of Outdoor Apparatus Insulators

Most apparatus insulators are available in several mechanical strength ratings, based primarily on the cantilever strength of the insulators. The various ratings available can be found in ANSI and NEMA Standards and in manufacturers' literature.

The design and manufacture of post type apparatus insulators allow equal cantilever strength ratings in both upright and underhung mounting positions. Cap and pin apparatus insulators, however, have somewhat lower cantilever strengths in the underhung position than in the upright position. It is important to consider this difference when using cap and pin insulators.

For most applications, cantilever strength is the most important mechanical characteristic. However, depending on the actual insulator application, some of the other characteristics can become important and should be considered. These insulator characteristics include tensile strength, compressive strength, and torsional strength.

Typical characteristics of cap and pin type and post type apparatus insulators can be found in Tables IV-3 and IV-4, respectively.

TABLE IV-3

Typical Characteristics of Cap and Pin Type Apparatus Insulators

BIL (Impulse Withstand) kV	Technical Reference Number	Upright Cantilever Strength newtons	(pounds)	Underhung Cantilever Strength newtons	(pounds)	Bolt Circle centimeters	(inches)	Height centimeters	(inches)	Leakage Distance centimeters	(inches)
110	4	8,896	(2000)	4,448	(1000)	7.62	(3)	25.4	(10)	30.5	(12)
110	44	17,792	(4000)	13,344	(3000)	12.7	(5)	25.4	(10)	35.6	(14)
150	7	8,896	(2000)	4,448	(1000)	7.62	(3)	30.5	(12)	50.8	(20)
150	46	17,792	(4000)	13,344	(3000)	12.7	(5)	30.5	(12)	45.7	(18)
200	10	8,896	(2000)	4,448	(1000)	7.62	(3)	38.1	(15)	71.1	(28)
200	49	17,792	(4000)	13,344	(3000)	12.7	(5)	38.1	(15)	71.1	(28)
250	13	8,896	(2000)	4,448	(1000)	7.62	(3)	45.7	(18)	91.4	(36)
250	53	17,792	(4000)	11,120	(2500)	12.7	(5)	50.8	(20)	102	(40)
350	16	6,672	(1500)	4,448	(1000)	7.62	(3)	73.7	(29)	132	(52)
350	56	13,344	(3000)	10,453	(2350)	12.7	(5)	73.7	(29) (1)	168	(66)
550	19	7,562	(1700)	6,539	(1470)	12.7	(5)	111	(43.5)(1)	252	(99)
550	173	12,899	(2900)	10,675	(2400)	12.7	(5)	111	(43.5)(1)	252	(99)
650	22	6,450	(1450)	5,560	(1250)	12.7	(5)	125	(49) (1)	269	(106)
650	180	10,453	(2350)	8,451	(1900)	12.7	(5)	125	(49) (1)	269	(106)
750	25	5,338	(1200)	4,759	(1070)	12.7	(5)	147	(58) (1)	335	(132)
750	123	8,896	(2000)	7,784	(1750)	12.7	(5)	147	(58) (1)	335	(132)
900	126	4,048	(910)	3,736	(840)	12.7	(5)	184	(72.5)(1)	419	(165)
900	27	6,450	(1450)	6,005	(1350)	12.7	(5)	184	(72.5)(1)	419	(165)
1050	128	3,336	(750)	3,114	(700)	12.7	(5)	221	(87) (1)	503	(198)
1050	28	5,204	(1170)	4,893	(1100)	12.7	(5)	221	(87) (1)	503	(198)

Notes:
(1) Does not include 8.89 centimeter (3.5 inch) high sub-base that is required for full BIL.
(2) The insulators listed are representative of those currently available. Additional ratings are available for some voltages. Refer to manufacturers' data for information.
(3) The characteristics listed are typical. Refer to manufacturers' data for actual ratings and additional characteristics.

TABLE IV-4

Typical Characteristics of Post Type Apparatus Insulators

BIL (Impulse Withstand) kV	Technical Reference Number	Upright Cantilever Strength newtons	(pounds)	Underhung Cantilever Strength newtons	(pounds)	Bolt Circle centimeters	(inches)	Height centimeters	(inches)	Leakage Distance centimeters	(inches)
110	205	8,896	(2000)	8,896	(2000)	7.62	(3)	25.4	(10)	39.4	(15.5)
110	225	17,792	(4000)	17,792	(4000)	12.7	(5)	30.5	(12)	39.4	(15.5)
150	208	8,896	(2000)	8,896	(2000)	7.62	(3)	35.6	(14)	61.0	(24)
150	227	17,792	(4000)	17,792	(4000)	12.7	(5)	38.1	(15)	61.0	(24)
200	210	8,896	(2000)	8,896	(2000)	7.62	(3)	45.7	(18)	94.0	(37)
200	231	17,792	(4000)	17,792	(4000)	12.7	(5)	50.8	(20)	94.0	(37)
250	214	8,896	(2000)	8,896	(2000)	7.62	(3)	55.9	(22)	109	(43)
250	267	17,792	(4000)	17,792	(4000)	12.7	(5)	61.0	(24)	109	(43)
350	216	6,672	(1500)	6,672	(1500)	7.62	(3)	76.2	(30)	183	(72)
350	278	13,344	(3000)	13,344	(3000)	12.7	(5)	76.2	(30)	183	(72)
550	286	7,562	(1700)	7,562	(1700)	12.7	(5)	114	(45)	251	(99)
550	287	12,899	(2900)	12,899	(2900)	12.7	(5)	114	(45)	251	(99)
650	288	6,450	(1450)	6,450	(1450)	12.7	(5)	137	(54)	295	(116)
650	289	10,898	(2450)	10,898	(2450)	12.7	(5)	137	(54)	295	(116)
750	291	5,338	(1200)	5,338	(1200)	12.7	(5)	157	(62)	335	(132)
750	295	8,896	(2000)	8,896	(2000)	12.7	(5)	157	(62)	335	(132)
900	304	4,048	(910)	4,048	(910)	12.7	(5)	203	(80)	419	(165)
900	308	6,450	(1450)	6,450	(1450)	12.7	(5)	203	(80)	419	(165)
1050	312	3,336	(750)	3,336	(750)	12.7	(5)	234	(92)	503	(198)
1050	316	5,204	(1170)	5,204	(1170)	12.7	(5)	234	(92)	503	(198)

Notes: (1) The insulators listed are representative of those currently available. Additional ratings are available for some voltages. Refer to manufacturers' data for information.

(2) The characteristics listed are typical. Refer to manufacturers' data for actual ratings and additional characteristics.

g. Mounting Outdoor Apparatus Insulators

Most apparatus insulators are furnished with end caps with four mounting holes arranged in either 7.62 centimeter (3 inch), 12.7 centimeter (5 inch) or 17.8 centimeter (7 inch) bolt circles, depending on the insulator strength and voltage rating. The mounting holes are usually tapped for 1/2"-13 threads per inch, 5/8"-11 threads per inch, or 3/4"-10 threads per inch bolts, respectively. Adapters are available to go from one bolt circle size to another.

Upright or underhung mounting usually does not present major problems, provided the insulators are utilized within their mechanical and electrical capabilities. When the insulators are installed horizontally, the weight of the insulators, fittings, buses, and any other supported equipment must be considered to determine the permissible loads. Some manufacturers recommend reducing the allowable loads from the tabulated values for horizontally mounted insulators. Unusual applications can be referred to the manufacturers for recommendations.

2. Suspension Insulators

a. Types

Suspension insulators are used as insulation and support for strain buses in substations. Suspension insulators are available in several forms to suit individual requirements. Distribution dead-end type suspension insulators can be used at distribution voltages for substation strain buses. Distribution dead-end type suspension insulators normally have clevis type connections. Conventional suspension insulators are normally used for strain bus insulation at higher voltages and can be furnished with either clevis or ball and socket type connections. The conventional suspension insulators most commonly used, are 25.4 centimeters (10 inches) in diameter and 14.6 centimeters (5-3/4 inches) in length.

Suspension insulators acceptable for use on REA financed systems are listed in REA Bulletin 43-5, Item k.

b. Electrical Characteristics of Suspension Insulators

To achieve the necessary electrical characteristics, a number of suspension insulators are strung together in series. It is important to coordinate the insulation characteristics of suspension insulator strings with the insulation systems of other substation equipment and the characteristics of various insulation protective devices.

The quantity of suspension insulators chosen for a particular application should be large enough to prevent unnecessary flashovers. Overinsulation, however, can result in flashovers occurring from phase to phase rather than from phase to ground. Consequently, the quantity of insulators should be small enough that all flashovers occur to ground.

Table IV-5 lists the recommended minimum quantities of standard 14.6 x 25.4 centimeter (5-3/4 x 10 inch) suspension insulators for particular nominal system voltages and BIL's. Above 1000 meters (3300 feet), the correction factors listed in Table IV-2 should be applied to the BIL's and the insulator quantities correspondingly increased. In areas of high contamination, it may be necessary to increase the insulator quantities or consider the use of specially designed equipment.

TABLE IV-5

Minimum Quantity of Suspension Insulators

Nominal System Phase-to-Phase Voltage kV	BIL kV	Minimum Quantity of Suspension Insulators*
14.4	110	2
23	150	2
34.5	200	3
46	250	4
69	350	5
115	550	8
138	650	9
161	750	10
230	900	12
230	1050	14

* For standard 14.6 x 25.4 centimeter (5-3/4 x 10 inch) suspension insulators

c. Mechanical Strength of Suspension Insulators

Suspension insulators are tested and categorized with simultaneous mechanical-electrical strength ratings, as listed in REA Bulletin 43-5. These strength ratings are not the actual loads the insulators are designed to operate under, but represent ultimate strengths. The insulators also have proof test ratings specified in ANSI C29.2 as one half of the mechanical-electrical ratings. These ratings are the actual loads that the insulators have withstood during testing. The maximum suspension insulator loading should not exceed 40 percent of the mechanical-electrical strength ratings listed in REA Bulletin 43-5.

I. ELECTRICAL CLEARANCES

Table IV-6 lists the electrical clearances for outdoor substation construction based on ANSI C37.32, "Schedules of Preferred Ratings, Manufacturing Specifications, and Application Guide for High Voltage Air Switches, Bus Supports, and Switch Accessories," and NEMA SG6, "Power Switching Equipment." The values identified as minimums should be maintained or exceeded at all times. Phase-to-ground clearances and phase-to-phase clearances should be coordinated to ensure that possible flashovers occur from phase-to-ground rather than from phase-to-phase.

Table IV-7 lists the phase spacing of various types of outdoor air switches, based on ANSI C37.32 and NEMA SG6. The minimum metal-to-metal clearances should be maintained at all times with the switches in the open position, closed position, or anywhere between the open and closed positions.

When nonrigid conductors are used for outdoor overhead substation buses, the movement of the conductors caused by temperature changes and wind and ice loads must be considered. The usual practice is to increase the centerline-to-centerline bus spacing and the phase-to-ground clearances to compensate for these conditions. The minimum metal-to-metal, bus centerline-to-centerline, and minimum ground clearances listed in Table IV-6 should be increased at least 50 percent for nonrigid conductors. Checks should be made to ensure that the minimum metal-to-metal clearances listed in Tables IV-6 and IV-7 are maintained or exceeded at all times for all expected temperature and loading conditions.

In some locations, contamination from airborne particles necessitates increasing the minimum electrical clearances. Usually satisfactory operation can be obtained by using clearances one step above those normally used. In extremely contaminated locations, additional clearance may be required.

Since the dielectric strength of air insulated equipment decreases with increasing altitude, the clearances listed in Table IV-6 must be modified for use at altitudes above 1000 meters (3300 feet). To determine appropriate clearances for use above 1000 meters (3300 feet), first derate the standard BIL's by applying the factors listed in Table IV-2. Then choose the clearances from Table IV-6 corresponding to the derated BIL's selected. For example, at an altitude of 2400 meters (8000 feet), a maximum voltage of 121 kV is to be used. From Table IV-2, the standard BIL of 550 kV must be derated by applying a

multiplying factor of 0.86. The following table shows the effects of derating for 2400 meters (8000 feet):

Standard BIL's kV	Derated BIL's kV
550	473
650	559
750	645

A 650 kV BIL must be selected for use at 2400 meters (8000 feet) to provide a BIL equivalent to 550 kV at altitudes of 1000 meters (3300 feet) and below. The clearances to be used are those associated with the 650 kV standard BIL, as listed in Tables IV-6 and IV-7.

TABLE IV-6

Outdoor Electrical Substation Clearances

Nominal Phase-to-Phase Voltage kV	Maximum Phase-to-Phase Voltage kV	BIL kV	Minimum Metal-to-Metal for Rigid Conductors meters(inches)	Centerline-to-Centerline Phase Spacing for Rigid Buses meters(inches)	Minimum to Grounded Parts for Rigid Conductors meters(inches)	Minimum Between Bare Overhead Conductors and Ground for Personnel Safety meters (feet) (3)	Minimum Between Bare Overhead Conductors and Roadways Inside Substation Enclosure meters (feet)
14.4	15.5	110	0.305 (12)	0.610 (24)	0.178 (7)	2.74 (9)	6.10 (20)
23	25.8	150	0.381 (15)	0.762 (30)	0.254 (10)	3.05 (10)	6.71 (22)
34.5	38	200	0.457 (18)	0.914 (36)	0.330 (13)	3.05 (10)	6.71 (22)
46	48.3	250	0.533 (21)	1.22 (48)	0.432 (17)	3.05 (10)	6.71 (22)
69	72.5	350	0.787 (31)	1.52 (60)	0.635 (25)	3.35 (11)	7.01 (23)
115	121	550	1.35 (53)	2.13 (84)	1.07 (42)	3.66 (12)	7.62 (25)
138	145	650	1.60 (63)	2.44 (96)	1.27 (50)	3.96 (13)	7.62 (25)
161	169	750	1.83 (72)	2.74 (108)	1.47 (58)	4.27 (14)	7.92 (26)
230	242	900	2.26 (89)	3.35 (132)	1.80 (71)	4.57 (15)	8.23 (27)
230	242	1050	2.67 (105)	3.96 (156)	2.11 (83)	4.88 (16)	8.53 (28)

Notes:
(1) Values taken from ANSI C37.32 and NEMA SG6.
(2) Values listed are for altitudes of 1000 meters (3300 feet) or less. For higher altitudes, the altitude correction factors listed in Table IV-2 should be applied.
(3) This is the minimum clearance from the top of structure, equipment, or apparatus foundations to energized conductors.
(4) In no cases should the clearance from the top of a foundation to the bottom of equipment bushings or insulators of energized equipment or apparatus be less than 2.44 meters (8 feet).

TABLE IV-7

Phase Spacing of Outdoor Air Switches

Nominal Phase-to Phase Voltage kV	Maximum Phase-to Phase Voltage kV	BIL kV	Minimum Metal-to-Metal for Air Switches meters (inches)	Centerline-to-Centerline Phase Spacing meters (inches): Vertical Break Disconnect Switches	Side or Horizontal Break Disconnect Switches	All Horn Gap Switches
14.4	15.5	110	0.305 (12)	0.610 (24)	0.762 (30)	0.914 (36)
23	25.8	150	0.381 (15)	0.762 (30)	0.914 (36)	1.22 (48)
34.5	38	200	0.457 (18)	0.914 (36)	1.22 (48)	1.52 (60)
46	48.3	250	0.533 (21)	1.22 (48)	1.52 (60)	1.83 (72)
69	72.5	350	0.787 (31)	1.52 (60)	1.83 (72)	2.13 (84)
115	121	550	1.35 (53)	2.13 (84)	2.74 (108)	3.05 (120)
138	145	650	1.60 (63)	2.44 (96)	3.35 (132)	3.66 (144)
161	169	750	1.83 (72)	2.74 (108)	3.96 (156)	4.27 (168)
230	242	900	2.26 (89)	3.35 (132)	4.87 (192)	4.87 (192)
230	242	1050	2.67 (105)	3.96 (156)	5.50 (216)	5.50 (216)

Notes: (1) Values taken from ANSI C37.32 and NEMA SG6.
(2) Values listed are for altitudes of 1000 meters (3300 feet) or less. For higher altitudes, the altitude correction factors listed in Table IV-2 should be applied.

In addition to the electrical clearances previously described, it is necessary to provide adequate space for equipment maintenance. In arrangements where equipment such as power circuit breakers, reclosers, disconnect switches, power transformers, or other equipment must be maintained while portions of adjacent equipment remain energized, sufficient space should be provided around the equipment to prevent accidental contact by maintenance personnel.

In arrangements with buses or equipment crossing over other buses and equipment, adequate clearance must be maintained between the adjacent buses and equipment for all operational conditions. Power transformers and power circuit breakers should be positioned to permit removal of any bushing. Switches and other equipment with externally moving parts should be located to prevent infringement on the minimum clearances listed in Tables IV-6 and IV-7 during operation or when in any position. Conductor, equipment, or support structure movement during heavily loaded or deformed conditions must be considered.

The clearances listed in Tables IV-6 and IV-7 are adequate for most situations and exceed the requirements of the National Electrical Safety Code. The clearances listed in the NESC must be maintained or exceeded at all times.

J. BARE CONDUCTORS

1. Conductor Materials

Copper and aluminum are the two major conductor materials used for substation buses and equipment connections. Both materials can be fabricated into various types of flexible or rigid conductors. The trend in substation construction is toward use of mostly aluminum conductors. Copper conductors are used principally for expansion of similar systems in existing substations.

The conductivity of aluminum is from 50 to 60 percent that of copper, depending on the aluminum alloy. Consequently, larger aluminum conductors are required to carry the same currents as the copper conductors. The larger aluminum conductor diameters result in greater wind and ice loads, but tend to minimize corona, which is more of a problem at higher voltages.

For the same ampacity, copper conductors weigh approximately twice as much as aluminum conductors. The higher copper conductor weights can result in more sag as compared with aluminum conductors for equal spans. To reduce the sag, it is usually necessary to increase the number of supports for rigid conductors or, in the case of flexible conductors, increase the tensions.

2. Rigid Conductors

Rigid electrical conductors are available in a variety of shapes and sizes to suit individual requirements. Some of the more commonly used shapes include flat bars, structural shapes, and tubes. Specific physical and electrical properties and application data can be obtained from the conductor manufacturers.

a. Flat Bars

Flat bars can be utilized for outdoor substation buses and are particularly suitable since they can be easily bent and joined. For high current applications, a number of flat bars can be grouped together leaving a small space between the bars to facilitate heat dissipation. The ampacity of a group of flat bars is dependent upon whether the bars are arranged vertically or horizontally. The number of bars that can be grouped together is limited because of skin and proximity effects.

Because of their inherent lack of rigidity, supports for flat bar buses are usually closely spaced to minimize the effects of meteorological loads and short circuit forces.

Flat bars are usually limited to use at lower voltages because of corona.

b. Structural Shapes

The structural shape conductors that have been used in outdoor substation construction consist primarily of angle and channel types. The flat surfaces permit bolting directly to support insulators and provide convenient connection points. To increase ampacity, two angles or channels can be used. Special fittings are usually required for these configurations. The

positioning and grouping of structural shapes have similar limitations to those of flat bars.

The rigidity of both angle and channel shapes is somewhat higher than for flat bars of the same ampacity. Consequently, support spacing can usually be increased.

c. Tubular Shapes

Square and round tubular shapes are considerably more rigid than either flat bars or structural shapes of the same ampacity and permit longer spans. The flat surfaces of square tubes provide convenient connection and support points. To facilitate heat dissipation, ventilation holes are sometimes provided in the square tubes. Round tubular conductors are the most popular shape used in outdoor substation construction. The round shape is very efficient structurally and electrically and minimizes corona at higher voltages. The special fittings required for connecting, terminating and supporting round tubular conductors are widely available.

d. Special Shapes

Special shapes combining the advantages of several of the standard shapes are also available. Integral web channel buses, uniform thickness angles, and other special configurations can be furnished.

e. Aluminum Alloys and Tempers

Aluminum conductors are available in a variety of alloys and tempers with different conductor conductivities and strengths. Round tubular conductors are usually specified as either 6061-T6 or 6063-T6 alloy. The 6063-T6 alloy has a conductivity approximately 23 percent higher and a minimum yield strength approximately 29 percent lower than the 6061-T6 alloy. Consequently, the 6063-T6 alloy can carry higher currents but may require shorter support intervals.

Both schedule 40 and 80 pipe are available in either alloy. The schedule 80 sizes have wall thicknesses approximately 40 percent thicker than the schedule 40 sizes resulting in lower deflections for equal span lengths.

Alloy 6106-T61 is frequently utilized for flat bars, structural shapes, and square tubes. Other alloys and tempers are available for special applications.

3. Flexible Conductors

Flexible electrical conductors can be used as substation buses and equipment taps. The conductors are normally cables fabricated by stranding a number of small conductors into one larger conductor. Stranding provides the required conductor flexibility while maintaining strength. The flexibility can be increased by reducing the diameter and increasing the quantity of individual conductors. Bare electrical cables for substation construction are usually concentric lay stranded with Class A or AA stranding per ASTM B231.

Most flexible conductors used in substation construction are all copper, all aluminum or aluminum with steel reinforcing (ACSR). The conductor type selected for a particular application is usually based on the span length, tension and tolerable sag, and cost. For long spans, large supporting structures will be required. The size and cost of these structures may depend on the conductor type and should be considered during the selection process.

Flexible conductors are available in many sizes. Size selection is based on ampacity, strength, weight, and diameter. Conductor diameter becomes increasingly important at higher voltages where corona can be a problem.

Data concerning the physical and electrical properties of the various wire types can be found in manufacturers' literature.

4. Conductor Ampacity

The ampacity of bare conductors is based on a number of factors, including the conductor material, proximity of the conductors, climatic conditions, conductor temperature rise, emissivity, and altitude.

Copper conductors can carry about 1.3 or more times as much current as aluminum conductors of the same size. However, based on weight, more than twice as much copper is required for the same ampacity.

The current distribution of closely spaced conductors is affected by their mutual inductance in accordance with the proximity effect. The additional losses attributed to this effect can usually be neglected if conductor spacing is 45.7 centimeters (18 inches) or greater.

Climatic conditions have a great effect on conductor ampacity. Ampacities are usually determined based on ambient temperatures of 40°C (104°F). For prolonged ambient temperatures above this value, ampacities are usually reduced. Wind tends to reduce the temperature of outdoor bare conductors. An assumed steady wind may be reasonable in many areas. The sun's radiation can cause the temperature of bare conductors to increase, which results in lower ampacities and should be considered in predominately sunny locations.

Conductor temperature rise is the temperature increase above ambient at which the conductor is operating. To prevent excessive surface oxidation and possible damage from annealing, the temperature rise is usually limited to 30°C (54°F) for a total maximum conductor temperature of 70°C (158°F) under normal operating conditions. The trend is toward higher operating temperatures. Temperature rises of 50°C (90°F) and higher have been used successfully. However, temperatures that could damage the conductors or connected equipment should be avoided.

The conductor surface emissivity has an effect or conductor ampacity. For aluminum conductors, emissivity is usually taken as 0.5 and for copper conductors 0.8. Both of these values are for heavily weathered conductor surfaces. The ampacity is usually higher for greater emissivity.

According to ANSI C37.30, "Definitions and Requirements for High-Voltage Air Switches, Insulators, and Bus Supports," equipment that depends on air for its cooling medium will have a higher temperature rise when operated at higher altitudes than when operating at lower altitudes. For altitudes in excess of 1000 meters (3300 feet), the correction factors listed in Table VI-8 should be applied. Consider a conductor with an ampacity of 1000 amperes in a 40°C (104°F) ambient temperature with a 30°C (54°F) temperature rise at an altitude of 1000 meters (3300 feet). If this conductor is to be used at a higher

altitude, the ampacity must be corrected. At 5400 meters (18,000 feet), this conductor will have an ampacity of 1000 x 0.910=910 amperes in an ambient temperature of 40°C (104°F) with a 30°F (54°F) temperature rise. The conductor may be operated at 1000 amperes at 5400 meters (18,000 feet), provided the ambient temperature does not exceed 40°C x 0.824=33°C (104°F x 0.824=85.7°F) and the temperature rise does not exceed 30°C (54°F).

TABLE IV-8

Altitude Correction Factors

Altitude meters (feet)	Correction Factors to be applied to Current Rating*	Correction Factors to be applied to Ambient Temperature*
1000 (3300)	1.00	1.00
1200 (4000)	0.995	0.992
1500 (5000)	0.990	0.980
1800 (6000)	0.985	0.968
2100 (7000)	0.980	0.956
2400 (8000)	0.970	0.944
2700 (9000)	0.965	0.932
3000 (10,000)	0.960	0.920
3600 (12,000)	0.950	0.896
4200 (14,000)	0.935	0.872
4800 (16,000)	0.925	0.848
5400 (18,000)	0.910	0.824
6000 (20,000)	0.900	0.800

*The correction factors for current rating and ambient temperature should not be applied at the same time.

5. Bus Connections

a. General

It is customary to purchase rigid bus conductors in lengths ranging from 3.05 meters (10 feet) to 12.2 meters (40 feet). Sections must be joined together for longer lengths. Taps are required from buses to electrical equipment. Bus conductors must be attached to support insulators. For greatest reliability and lowest cost, the fewer the connections the better.

The various substation bus connections can be made by using any of four main methods-bolting, clamping, compressing and welding-depending on the conductor type and material. Bolted connections are utilized in connecting two or more flat surfaces together. Clamp type connections generally involve the use of special fittings fabricated to permit conductors to be joined together or connected to other equipment. Compression connections are principally used for splicing or terminating flexible conductors. Welded connections are used primarily with rigid aluminum conductors. Weldment fittings are available that eliminate extensive conductor cutting and shaping prior to welding.

Whenever connectors are utilized for making electrical connections, they should be equivalent electrically and mechanically to the conductors themselves. Substation connectors are designed, manufactured, and tested in accordance with NEMA CC1, "Electric Power Connectors for Substations."

b. Bolted Connections

Bolted connections are the primary means used to make connections to equipment terminals. Bolted joints permit the disconnection of equipment for maintenance or replacement.

The most common bolted connection involves joining a conductor to an equipment terminal. A terminal lug is attached to the conductor by clamping, compressing, or welding, and the lug is bolted to the equipment terminal.

When a copper conductor is connected to a flat copper or electrical bronze equipment terminal, a copper or electrical bronze terminal lug is utilized. The lug is usually bolted to the equipment terminal with a minimum of two 1/2 inch-13 threads per inch high strength silicon bronze bolts normally torqued to 54.23 newton-meters (40 pound-feet). Silicon bronze flat washers are normally used under both the bolt heads and the nuts.

When an aluminum conductor is connected to a flat aluminum equipment terminal, an aluminum terminal lug is utilized. The lug is usually bolted to the equipment terminal with a minimum of two 1/2 inch-13 threads per inch anodized aluminum bolts normally torqued to 33.9 newton-meters (25 pound-feet). The bolts are usually aluminum alloy 2024-T4 and the nuts alloy 6061-T6. Flat washers of aluminum alloy 2024-T4 are normally used under both the bolt heads and the nuts. An anti-oxidation compound should also be considered for aluminum to aluminum connections.

When a copper conductor is connected to a flat aluminum equipment terminal, a copper or electrical bronze terminal lug is utilized. The lug is usually bolted to the equipment terminal with a minimum of two 1/2 inch-13 threads per inch bolts, normally of stainless steel or tin plated high strength silicon bronze. Flat washers of the same material as the other hardware are used under both the bolt heads and the nuts. Stainless steel spring washers are used between the flat washers and the nuts. Bolts are torqued to the spring washer manufacturer's recommendations.

When an aluminum conductor is connected to a flat copper or electrical bronze equipment terminal, an aluminum terminal lug is utilized. The lug is usually bolted to the equipment terminal with a minimum of two 1/2 inch-13 threads per inch bolts, normally of stainless steel or tin plated high strength silicon bronze. Flat washers of the same material as the other hardware are used under both the bolt heads and nuts. Stainless steel spring washers are used between the flat washers and the nuts. Bolts are torqued to the spring washer manufacturer's recommendations.

For aluminum-copper connections, the copper component should be installed below the aluminum component to prevent the copper salts from washing onto the aluminum. Additionally, the aluminum component should be massive, compared with the copper component. In many cases the copper connector should be tinned.

c. Clamp-Type Connections

A large variety of clamp-type electrical connectors are available for both flexible and rigid conductors of copper and aluminum. Most clamp-type connectors achieve their holding ability as a result of tightening a number of bolts. The quantities and sizes of bolts used should be as listed in NEMA CC1.

Copper or electrical bronze connectors should be utilized with copper conductors. All aluminum connectors should be used with aluminum conductors.

d. Compression Connections

Compression connections are primarily used in splicing or installing terminal lugs on flexible conductors. All-aluminum compression connectors should be used for aluminum conductors. Copper compression connectors should be used for copper conductors.

Installation of compression connectors in a vertical position with the lug down should be avoided to prevent the entrance of moisture and possible damage from freezing.

Compression connectors should always be installed in strict accordance with the manufacturer's instructions concerning the quantity and location of compressions. Connectors designed for a minimum of two circumferential compressions are recommended.

e. Welded Connections

Welded connections are used primarily with round tubular aluminum conductors. Use of the special fittings available simplifies the procedures to permit faster installation. Properly made welded connections have resistances that are not appreciably

higher than the conductors themselves to eliminate conductor hot spots.

Welded aluminum connections are extensively used in the construction of large substations. Construction costs are usually slightly less with welded, compared to clamp type, connections. In smaller installations with fewer connections, it may not be economically feasible to weld connections.

K. RIGID BUS DESIGN

1. General Considerations

The design of a rigid bus system involves many factors, including:

a. Bus location in the substation and its proximity to other equipment. Ample clearance should be provided to permit equipment maintenance and removal. The bus should be situated to allow entrance of construction and maintenance equipment into the substation.

b. Future substation expansion. It is important to plan for future expansion by sizing and positioning buses to facilitate modifications.

c. Conductor selection. The bus conductors are selected based on ampacity, physical properties, and cost. Conductors must be selected so that they have sufficient size and capacity to withstand system faults and overcurrents without damage from overheating.

d. Short circuit conditions. During short circuits, large forces can be developed in the bus system. The rigid bus design includes consideration of these forces to prevent damage during short circuit conditions. The bus centerline to-centerline spacing and the short circuit current both have effects on these forces.

e. Wind and ice load. If not properly considered, wind and ice loads can cause extensive damage to bus conductors and insulators. The usual practice is to consider National Electrical Safety Code loadings as a minimum. Local conditions should be considered, since they may necessitate the use of more severe loading criteria.

f. Insulator strength. Since the number of different insulator ratings is limited, care should be exercised in the bus layout, so that a practical system is achieved. The strength of the insulators required is based on the total bus loading and particularly the short circuit forces.

g. Conductor sag. The sag of the bus conductors should be limited in the design. A flat horizontal system looks much neater than one with excessive sag. The conductor sag is influenced by the conductor weight and section modulus, the span length, and the vertical loading.

h. Aeolian vibration. Long conductor spans can be damaged by vibrations caused by winds. Excessive conductor sag can add to this problem. Span lengths whose natural frequency is near that set up by a wind that has a high recurrence should be avoided.

i. Conductor expansion. As the temperature of the conductors increases, longitudinal expansion occurs. If the bus system is not provided with means to absorb this expansion, insulators or other connected equipment can be damaged.

j. Location of conductor couplers. Long buses usually require the use of more than one section of conductor. Consequently, couplers must be utilized to join the sections together. These couplers must be properly located to prevent damage from bus loading and short circuit forces.

The bus system should be carefully planned by considering these aspects and other factors as they may develop. This section deals with the design of the conductor and support insulator systems. For data concerning supporting structures, refer to Chapter VII.

2. <u>Procedure For Rigid Bus Design</u>

The following procedure can be used in designing a rigid bus system:

a. Select the material and size of the bus conductors based on continuous current requirements. In higher voltage systems with longer bus spans, the structural capabilities of the conductors may be the factor that

determines the conductor material and size. However, the conductors selected must be capable of carrying the required continuous current in any case.

b. Using Tables IV-6 and IV-7 from Section I of this chapter, determine the bus conductor centerline-to-centerline spacing.

c. Calculate the maximum short circuit forces the bus must withstand. These forces can be determined from the following equations:

$$F_{SC} = 13.9 \times 10^{-5} K_{SC} \frac{i^2}{D} \qquad \left(F_{SC} = 37.4 \times 10^{-7} K_{SC} \frac{i^2}{D}\right) \qquad \text{IV-1}$$

F_{SC}: maximum short-circuit force on center conductor for a three phase flat bus configuration of round or square tubular conductors with the conductors equally spaced, in newtons per meter (pounds per foot)

K_{SC}: short-circuit force reduction factor (0.5 to 1.0, 0.67 recommended)

i: rms value of three phase symmetrical short circuit current, in amperes

D: centerline-to-centerline spacing of bus conductors, in centimeters (inches)

d. Determine the total bus conductor loading. Table IV-9 lists values for wind and ice loading for the various loading districts defined in the National Electrical Safety Code. These values should be considered as minimum. Extreme wind should also be considered.

TABLE IV-9

NESC Conductor Wind and Ice Loads*

Load	Loading District Heavy	Medium	Light
Radial thickness of ice in centimeters (inches)	1.27(0.50)	0.635(0.25)	0
Horizontal wind pressure in pascals (pounds per square foot)	191.5(4.0)	191.5(4.0)	430.9(9.0)

*Conductor loading is usually based on these criteria. However, in locations where more severe conditions are frequent, the conductor loading should be based on actual local conditions.

The ice loading can be determined from the following equations:

$$W_I = 0.704\ (d_1^2 - d_2^2) \qquad (W_I = 0.311\ (d_1^2 - d_2^2)) \qquad \text{IV-2}$$

W_I: ice loading, in newtons per meter (pounds per foot)

d_1: outside diameter of conductor with ice, in centimeters (inches) (Determine ice thickness from Table IV-9.)

d_2: outside diameter of conductor without ice, in centimeters (inches)

The wind loading can be determined from the following equations:

$$F_W = 0.01\ P_W\ d_1 \qquad (F_W = 0.083\ P_W\ d_1) \qquad \text{IV-3}$$

F_W: wind loading, in newtons per meter (pounds per foot)

P_W: wind pressure, in pascals (pounds per foot^2) (from Table IV-9)

d_1: outside diameter of conductor with ice, in centimeters (inches)

The total bus conductor loading can be determined from the following equation:

$$F_T = [(F_{SC} + F_W)^2 + (W_C + W_I)^2]^{\frac{1}{2}} \qquad \text{IV-4}$$

F_T: total bus conductor loading, in newtons per meter (pounds per foot)

F_{SC}: maximum short circuit force, in newtons per meter (pounds per foot)

F_W: wind loading, in newtons per meter (pounds per foot)

W_C: conductor weight, in newtons per meter (pounds per foot) (If damping cables are used to control conductor vibration, add the cable weight to the conductor weight.)

W_I: ice loading, in newtons per meter (pounds per foot)

e. Calculate the maximum bus span or support spacing. This can be determined from the following equations:

$$L_M = K_{SM} \left[\frac{F_B S}{F_T} \right]^{\frac{1}{2}} \left(L_M = K_{SE} \left[\frac{F_B S}{F_T} \right]^{\frac{1}{2}} \right) \qquad \text{IV-5}$$

L_M: maximum bus support spacing, in meters (feet)

K_{SM}: multiplying factor from Table IV-10

K_{SE}: multiplying factor from Table IV-10

F_B: maximum desirable fiber stress of conductor, in kilopascals (pounds per inch^2)

For round tubular conductors of:

copper, $F_B = 1.38 \times 10^5$ kPa (20,000 lb/in^2)*

6061-T6 aluminum alloy,

$F_B = 1.93 \times 10^5$ kPa (28,000 lb/in^2)*

6063-T6 aluminum alloy,

$F_B = 1.38 \times 10^5$ kPa (20,000 lb/in^2)*

*Includes a safety factor of 1.25

S: section modulus of conductor, in $centimeters^3$ ($inches^3$)

F_T: total bus conductor loading, in newtons per meter (pounds per foot)

f. Calculate the maximum vertical conductor deflection from the following equations:

$$y = K_{DM} \frac{(W_C + W_I) L^4}{EI} \quad \left(y = K_{DE} \frac{(W_C + W_I) L^4}{EI}\right) \qquad \text{IV-6}$$

y: maximum vertical conductor deflection, in centimeters (inches) (Limit this value to 1/200 of the span length. If the value calculated is greater than 1/200 of the span length, select a conductor with a larger diameter or reduce the span length. Recalculate as required.)

K_{DM}: multiplying factor from Table IV-10

K_{DE}: multiplying factor from Table IV-10

W_C: conductor weight, in newtons per meter (pounds per foot) (If damping cables are used to control conductor vibration, add the cable weight to the conductor weight.)

W_I: ice loading, in newtons per meter (pounds per foot)

L: bus support spacing, in meter (feet)

E: modulus of elasticity, in kilopascals (pounds per inch^2)

I: moment of inertia, in centimeters^4 (inches^4)

TABLE IV-10

Conductor Maximum Span and Deflection Multiplying Factors (K_{SM}, K_{SE}, K_{DM}, K_{DE})

Bus System	K_{SM}	(K_{SE})	K_{DM}	(K_{DE})
Conductor fixed both ends (single span)	0.110	(1.0)	2.6×10^4	(4.50)
Conductor fixed one end, simply supported other end (single span)	0.090	(0.82)	5.4×10^4	(9.34)
Conductor simply supported (single span)	0.090	(0.82)	1.3×10^5	(22.5)
Conductor simply supported (two equal spans)*	0.090	(0.82)	5.4×10^4	(9.34)
Conductor simply supported (three or more equal spans)*	0.096	(0.88)	6.9×10^4	(11.9)

*Maximum deflection occures in end spans

g. Determine the minimum required support insulator cantilever strength from the following equation:

$$W_S = 2.5\ (F_{SC} + F_W)\quad L_S\ * \qquad \text{IV-7}$$

W_S: minimum insulator cantilever strength, in newtons (pounds)

F_{SC}: maximum short circuit force, in newtons per meter (pounds per foot)

F_W: wind loading, in newtons per meter (pounds per foot)

L_S: one half of the sum of the lengths of the two adjacent conductor spans, in meters (feet)

*This equation includes an insulator safety factor of 2.5.

Select support insulators from Table IV-3 or IV-4 in Section H of this chapter or from manufacturers' data with cantilever strength ratings equal to or greater than W_S. If sufficiently high ratings are not available, it will be necessary to modify the bus design. This can be done by increasing the centerline-to-centerline conductor spacing to reduce the short circuit forces or by decreasing the bus span lengths.

h. Provide for thermal expansion of conductors. The amount of conductor thermal expansion can be calculated from the following equation:

$$\Delta l = \alpha\, l\, \Delta T \qquad \text{IV-8}$$

Δl: conductor expansion, in centimeters (inches) (final length minus initial length)

α: coefficient of linear thermal expansion

for aluminum, $\alpha = 2.3 \times 10^{-5}$ per degree Celsius (1.3×10^{-5} per degree Fahrenheit)

for copper, $\alpha = 1.7 \times 10^{-5}$ per degree Celsius (9.2×10^{-6} per degree Fahrenheit)

l: initial conductor length, in centimeters (inches) (at initial temperature)

ΔT: temperature variation, in degrees Celsius (Fahrenheit) (final temperature minus initial temperature)

Bus sections with both ends fixed without provisions for conductor expansion should be avoided. Connections to power circuit breakers, power transformers, voltage transformers, and other device bushings or terminals that could be damaged by conductor movement should be made either with flexible conductors or expansion type connectors.

Connections to switches utilizing apparatus insulators may require the use of expansion type terminal connectors to prevent damage from excessive conductor expansion. Use of expansion type terminals in this situation is dependent upon the bus configuration and location of other expansion points. It is recommended that expansion fittings used on long horizontal buses be limited to those permitting longitudinal expansion only.

It is usually desirable to limit the length of sections of continuous buses to 30.48 meters (100 feet) or less to limit the amount of conductor expansion in each section. This can be done by fixing certain points in the bus and permitting other points to move freely. An example of a typical bus system is diagrammed in Figure IV-19.

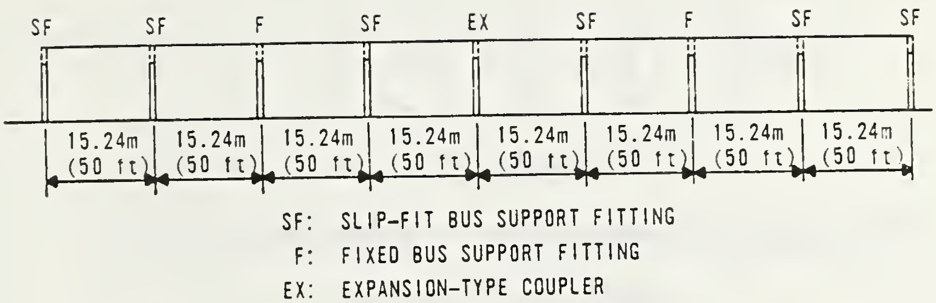


FIGURE IV-19 TYPICAL BUS SYSTEM ILLUSTRATING PROVISIONS FOR CONDUCTOR THERMAL EXPANSION

The system illustrated in Figure IV-19 can freely expand as necessary and is free of "captured spans" that permit no expansion. The locations of slip-fit and fixed bus supports and expansion-type couplers or bus supports divide the bus into four sections, each of which will expand approximately the same total amount. If it is desirable to connect the end sections of the bus to other equipment, flexible conductors or expansion-type connectors should be provided.

i. Locate conductor couplers. The couplers used on rigid buses should be as long as possible to provide maximum joint rigidity and strength. Clamp-type bolted couplers should have the quantity and size of clamping bolts as listed in NEMA CC1. Welded couplers for aluminum conductors should be of the internal type.

To prevent conductor damage from bending caused by its own weight and external loads, couplers should be carefully positioned. Welding and bolting can cause appreciable loss of conductor strength in the immediate coupler locations. Consequently, couplers

should be positioned where the least amount of bending will occur. The ideal locations are points of zero bending moment along the conductor.

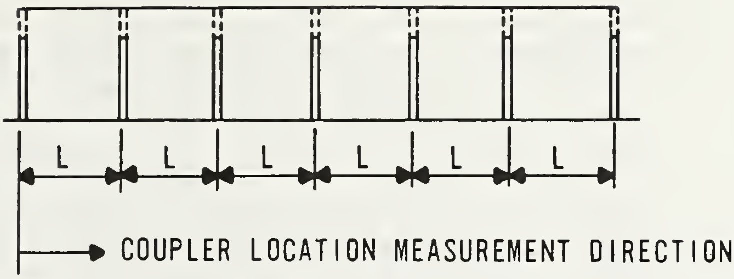
Table IV-11 lists the ideal locations for conductor couplers for continuous conductors.

TABLE IV-11

Ideal Locations for Couplers in Continuous Uniformly Loaded Rigid Conductors

Quantity of Conductor Spans	Ideal Coupler Locations Measured to the Right from the Left-most Support
1	*
2	0.750L, 1.250L
3	0.800L, 1.276L, 1.724L, 2.200L
4	0.786L, 1.266L, 1.806L, 2.194L, 2.734L, 3.214L
5	0.789L, 1.268L, 1.783L, 2.196L, 2.804L, 3.217L, 3.732L, 4.211L
6	0.788L, 1.268L, 1.790L, 2.196L, 2.785L, 3.215L, 3.804L, 4.210L 4.732L, 5.212L

*The zero moment locations for single span simply supported conductors are at the supports. Consequently, couplers are not recommended.



If couplers must be positioned in other than the ideal locations listed in Table IV-11, reduce the maximum allowable fiber stress used in Section 2(e) of this chapter by as much as 50 percent, dependent upon the degree of variation from the ideal location and recalculate the maximum span length. If the span length being considered exceeds this maximum, reduce it as necessary. Conductor couplers can now be positioned wherever convenient.

j. Consider aeolian conductor virbation. Aeolian conductor vibration is primarily the result of steady low velocity transverse winds striking the conductor and causing it to vibrate. When the frequency of the driving force (wind) is approximately equal to the natural frequency of the bus span, resonance occurs. The resulting vibrations can cause insulator damage.

Vibrations will occur in almost all bus spans independently of the conductor material, diameter, or length. In short spans, the vibrations are usually of small enough magnitude to be neglected. However,

in spans longer than about 6.1 meters (20 feet), methods for vibration damping should be considered.

Two primary methods have been used to dampen aeolian vibrations. The first and most widely used method consists of installing scrap cables in the horizontal buses. When this method is used, it is necessary that the cables be loose in the bus tubing to permit vertical movement. If new cables are used, they should be straightened prior to installation to prevent the cables from jamming against the tubing sides. Additionally, end caps, preferably of the driven type, should be installed on the ends of the buses containing the damping cables to prevent horizontal cable movement out of the tubing. To be effective, damping cables should be installed for the entire bus length for buses where excessive vibration is suspected.

The second method used to dampen aeolian vibrations consists of installing internal or external prefabricated bus dampers on the bus conductors. Usually, one damper is installed in each bus span to control the vibrations. Location and installation should be in accordance with the manufacturer's instructions.

3. Bus Design Example

Design a three phase rigid bus with the following characteristics:

Total bus length: 45.72 meters (150 feet), assuming four equal spans of 11.43 meters (37.5 feet)

Voltage: 161 kV

BIL: 750 kV

Insulator type: post

Continuous current rating: 1800 amperes

Short-circuit current: 24,000 rms symmetrical amperes

Altitude: 304.8 meters (1000 feet)

NESC loading: heavy

Disconnect switch connected to one end of bus

External prefabricated dampers will be used to control conductor vibration

Following the procedure of Section K of this chapter:

a. Select the material and size of the bus conductors. Based on the continuous current requirements, 7.6 cm (3 in) SPS, schedule 40 6063-T6 aluminum alloy (1890 amperes) is selected with the following properties:

W_C (weight) = 38.2 N/m (2.62 lb/ft)*

d_2 (outside diameter) = 8.89 centimeters (3.50 inches)

I (moment of inertia) = 125.6 cm^4 (3.017 in^4)

E (modulus of elasticity) = 6.9×10^7 kPa (10×10^6 lb/in^2)

S (section modulus) = 28.2 cm^3 (1.72 in^3)

F_B (maximum allowable fiber stress) = 1.38×10^5 kPa (20,000 lb/in^2)

*If damping cables are to be used to control conductor vibration, the cable weight must be added to the conductor weight. In this example, external prefabricated dampers will be used for vibration control.

b. Determine the bus conductor centerline-to-centerline spacing from Table IV-6.

D (bus centerline-to-centerline spacing) = 274 cm (108 in)

c. Calculate the maximum short circuit force.

$$F_{SC} = 13.9 \times 10^{-5} K_{SC} \frac{i^2}{D} \qquad (F_{SC} = 37.4 \times 10^{-7} K_{SC} \frac{i^2}{D})$$

$$F_{SC} = (13.9 \times 10^{-5})(0.67) \frac{(24,000)^2}{(274)} \qquad (F_{SC} = (37.4 \times 10^{-7})(0.67) \frac{(24,000)^2}{(108)})$$

$$F_{SC} = 195.8 \text{ N/m} \qquad (F_{SC} = 13.4 \text{ lb/ft})$$

d. Determine the total bus conductor loading. From Table IV-9, Radial thickness of ice: 1.27 cm (0.50 in)

Horizontal wind pressure: 191.5 Pa (4.0 lb/ft^2)

$$W_I = 0.704 (d_1^2 - d_2^2) \qquad (W_I = 0.311 (d_1^2 - d_2^2))$$

$$W_I = (0.704) [(11.43)^2 - (8.89)^2] \qquad (W_I = 0.311 [(4.50)^2 - (3.50)^2])$$

$$W_I = 36.3 \text{ N/m} \qquad (W_I = 2.49 \text{ lb/ft})$$

$$F_W = 0.01 P_W d_1 \qquad (F_W = 0.083 P_W d_1)$$

$$F_W = (0.01)(191.5)(11.43) \qquad (F_W = (0.083)(4.0)(4.50)$$

$$F_W = 21.9 \text{ N/m} \qquad (F_W = 1.49 \text{ lb/ft})$$

$$F_T = [(F_{SC} + F_W)^2 + (W_C + W_I)^2]^{1/2} \qquad (F_T = [(F_{SC} + F_W)^2 + (W_C + W_I)^2]^{1/2})$$

$$F_T = [(195.8 + 21.9)^2 + (38.2 + 36.3)^2]^{1/2} \qquad (F_T = [(13.3 + 1.49)^2 + (2.62 + 2.49)^2]^{1/2})$$

$$F_T = 230.1 \text{ N/m} \qquad (F_T = 15.6 \text{ lb/ft})$$

e. Calculate the maximum bus support spacing.

$$L_M = K_{SM} \left[\frac{F_B S}{F_T} \right]^{1/2} \qquad \left(L_M = K_{SE} \left[\frac{F_B S}{F_T} \right]^{1/2} \right)$$

Four equal spans of 11.43 meters (37.5 feet) were assumed. From Table IV-10, $K_{SM} = 0.096$ ($K_{SE} = 0.88$) for three or more equal spans.

$$L_M = (0.096) \left[\frac{(1.38 \times 10^5)(28.2)}{(230.1)} \right]^{1/2} \qquad \left(L_M = (0.88) \left[\frac{(20{,}000)(1.72)}{(15.6)} \right]^{1/2} \right)$$

$$L_M = 12.48 \text{ m} \qquad (L_M = 41.3 \text{ ft})$$

The assumed spacing of 11.43 meters (37.5 ft) is structurally permissible for the conductors.

f. Calculate the maximum vertical conductor deflection.

$$y = K_{DM} \frac{(W_C + W_I)\, L^4}{EI} \qquad \left(y = K_{DE} \frac{(W_C + W_I)\, L^4}{EI} \right)$$

Four equal spans of 11.43 meters (37.5 feet) were assumed. From Table IV-10, $K_{DM} = 6.9 \times 10^4$ ($K_{DE} = 11.9$) for three or more equal spans.

$$y = (6.9 \times 10^4) \cdot \frac{(38.2 + 36.3)(11.43)^4}{(6.9 \times 10^7)(125.6)} \qquad \left(y = (11.9) \cdot \frac{(2.62 + 2.49)(37.5)^4}{(10 \times 10^6)\ (3.017)} \right)$$

$$y = 10.1 \text{ cm} \qquad (y = 3.99 \text{ in})$$

Maximum permissible deflection is $\frac{1}{200}$ of the span length.

$$y_{max} = \frac{(11.43)(100)}{200} \qquad \left(y_{max} = \frac{(37.5)(12)}{200}\right)$$

$$y_{max} = 5.72 \text{ cm} \qquad (y_{max} = 2.25 \text{ in})$$

Since the calculated deflection is greater than the maximum permissible deflection, the design must be modified. The span length will be reduced to five equal spans of 9.14 meters (30 feet) each. The maximum vertical deflection is then recalculated.

$$y = (6.9 \times 10^4) \cdot \frac{(38.2 + 36.3)(9.14)^4}{(6.9 \times 10^7)(125.6)} \qquad \left(y = (11.9) \cdot \frac{(2.62 + 2.49)(30)^4}{(10 \times 10^6)(3.017)}\right)$$

$$y = 4.14 \text{ cm} \qquad (y = 1.63 \text{ in})$$

Maximum permissible deflection is:

$$y_{max} = \frac{(9.14)(100)}{200} \qquad \left(y_{max} = \frac{(30)(12)}{200}\right)$$

$$y_{max} = 4.57 \text{ cm} \qquad (y_{max} = 1.80 \text{ in})$$

Since the calculated value with 9.14 meter (30 foot) support spacing is less than the maximum permissible deflection, this support spacing is adequate.

g. Determine the minimum required support insulator cantilever strength.

$$W_S = 2.5\ (F_{SC} + F_W)\ L_S \qquad (W_S = 2.5\ (F_{SC} + F_W)\ L_S)$$

$$W_S = (2.5)(195.8 + 21.9) \cdot \left(\frac{9.14}{2} + \frac{9.14}{2} \right)$$

$$\left(W_S = (2.5)(13.3 + 1.49) \cdot \left(\frac{30}{2} + \frac{30}{2} \right)\right)$$

$$W_S = 4974 \text{ N}$$

$$(W_S = 1109 \text{ lb})$$

From Table IV-4, select Technical Reference Number 291 for 5338 newton (1200 pound) cantilever strength post type insulators.

h. Provide for conductor expansion. Assuming a total conductor temperature variation of 50°C (90°F), the total conductor expansion is:

$$\Delta 1 = \alpha 1 \Delta T$$

$$(\Delta 1 = \alpha 1 \Delta T)$$

$$\Delta 1 = (2.3 \times 10^{-5})(45.72) \cdot (100)(50)$$

$$(\Delta 1 = (1.3 \times 10^{-5})(150) \cdot (12)(90))$$

$$\Delta 1 = 5.26 \text{ cm}$$

$$(\Delta 1 = 2.11 \text{ in})$$

Some means must be provided to account for this change. Figure IV-20 illustrates one method that can be used that permits free expansion in all spans:

SF: Slip-fit bus support

F: Fixed bus support

EX: Expansion terminal

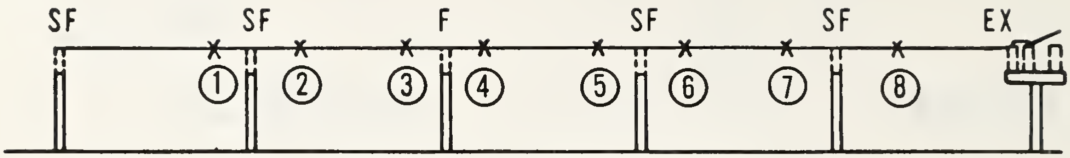


FIGURE IV-20 BUS CONFIGURATION FOR EXAMPLE

i. Locate conductor couplers. From Table IV-11, the ideal coupler locations for the five span bus of 9.14 meter (30 foot) spans measured to the right from the left-most support are as follows:

1	7.2 m	(23.7 ft)
2	11.6 m	(38.0 ft)
3	16.3 m	(53.5 ft)
4	20.1 m	(65.9 ft)
5	25.6 m	(84.1 ft)
6	29.4 m	(96.5 ft)
7	34.1 m	(112.0 ft)
8	38.5 m	(126.3 ft)

These locations are illustrated in Figure IV-20. Assuming that the bus conductor is available in 12.19 meter (40 foot) lengths, the couplers should be positioned at points 2, 4, 6 and 8. The conductor lengths are cut as required to position the couplers at these approximate locations.

j. Consider aeolian vibration. Since the spans are fairly long, damaging vibrations may occur. Consequently, a means for controlling the vibrations should be provided. Prefabricated dampers can be attached to the buses or scrap cables can be installed in the buses. If cables are used, the cable weight must be added to the conductor weight for the bus calculations.

L. STRAIN BUS DESIGN

1. General Considerations

Strain bus design involves many factors, including:

a. Bus location in the substation and its proximity to other equipment. The flexible conductors used for strain bus construction permit significant conductor movement. Consequently the conductors must be carefully positioned to prevent contact with other equipment and infringement upon minimum electrical clearances under all loading and climatic conditions. Equipment maintenance and removal should also be considered in locating buses and support structures.

b. Future substation expansion. Strain buses usually require large supporting structures. These structures can limit future expansion if not properly positioned.

c. Conductor selection. The conductor is selected based on ampacity, physical properties and cost. Conductors must be selected so that they have sufficient size and capacity to withstand system faults and overcurrents without damage from overheating.

d. Wind and ice load. Wind and ice can increase conductor sags and tensions appreciably. The usual practice is to consider National Electrical Safety Code loadings as a minimum. Local conditions should be considered, since they may necessitate the use of more severe loading criteria.

e. Insulator strength. The suspension insulators are selected based on the anticipated maximum loading conditions. The maximum loading should not exceed 40 percent of the mechanical-electrical strength ratings listed in REA Bulletin 43-5.

f. Span length. The span length influences the conductor sag. As the span length increases, the sag increases if the same tension is maintained. To limit the sag, the tensions can be increased. Springs can also be used to limit the tension and sag.

g. Sag and tension. Strain buses are usually positioned above other substation equipment. Conductor breakage

could result in equipment damage or outage. To prevent breakage and to minimize support structure size, the conductors are usually installed at tensions of approximately 13,350 newtons (3000 pounds) or less. Sag may increase because of the deflection of support structures.

h. Temperature variations. Temperature variations cause changes in the conductor lengths. As the conductor temperature increases, the sag increases and the tension decreases.

i. Tap loads. Taps from the conductors to other buses or equipment should be limited in tension to prevent damage to equipment. The taps are usually installed as slack connections.

2. <u>Procedure For Strain Bus Design</u>

The following procedure can be used to design a strain bus system:

a. Select the material and size of the bus conductors, based on continuous current requirements.

b. Using Tables IV-6 and IV-7 from Section I of this chapter, determine the bus conductor centerline-to-centerline spacing. As explained in Section I, the minimum metal-to-metal, bus centerline-to-centerline, and minimum ground clearances listed in Table IV-6 should be increased at least 50 percent for nonrigid conductors.

c. Select the quantity of suspension insulators from Table IV-5 in Section H of this chapter.

d. Determine the total bus conductor loading. Table IV-12 lists values for wind and ice loading for the various loading districts defined in the National Electrical Safety Code. These values should be considered as minimum.

TABLE IV-12

NESC Conductor Loading Criteria*

Load	Loading District Heavy	Medium	Light
Radial thickness of ice in centimeters (inches)	1.27(0.50)	0.635(0.25)	0
Horizontal wind pressure in pascals (pounds per square foot)	191.5(4.0)	191.5(4.0)	430.9(9.0)
Temperature in degrees Celsius (degrees Farenheit)	-18(0)	-9.4(+15)	-1.1(+30)
Constant (k) to be added to the resultant	4.38(0.30)	4.38(0.20)	0.73(0.05)

*Conductor loading is usually based on these criteria. However, in locations where more severe conditions frequently occur, the conductor loading should be based on actual local conditions.

The ice loading can be determined from the following equations:

$$W_I = 0.704\ (d_1^2 - d_2^2) \qquad (W_I = 0.311\ (d_1^2 - d_2^2)) \qquad \text{IV-9}$$

W_I: ice loading, in newtons per meter (pounds per foot)

d_1: outside diameter of conductor with ice, in centimeters (inches) (Determine ice thickness from Table IV-12.)

d_2: outside diameter of conductor without ice, in centimeters (inches)

The wind loading can be determined from the following equations:

$$F_W = 0.01\ P_W d_1 \qquad (F_W = 0.083\ P_W d_1) \qquad \text{IV-10}$$

F_W: wind loading, in newtons per meter (pounds per foot)

P_W: wind pressure, in pascals (pounds per foot^2) (from Table IV-12)

d_1: outside diameter of conductor with ice, in centimeters (inches) (Determine ice thickness from Table IV-12.)

The total bus conductor loading can be determined from the following equation:

$$F_T = [F_W^2 + (W_C + W_I)^2]^{\frac{1}{2}} + k \qquad \text{IV-11}$$

F_T: total bus conductor loading, in newtons per meter (pounds per foot)

F_W: wind loading, in newtons per meter (pounds per foot)

W_C: conductor weight, in newtons per meter (pounds per foot)

W_I: ice loading, in newtons per meter (pounds per foot)

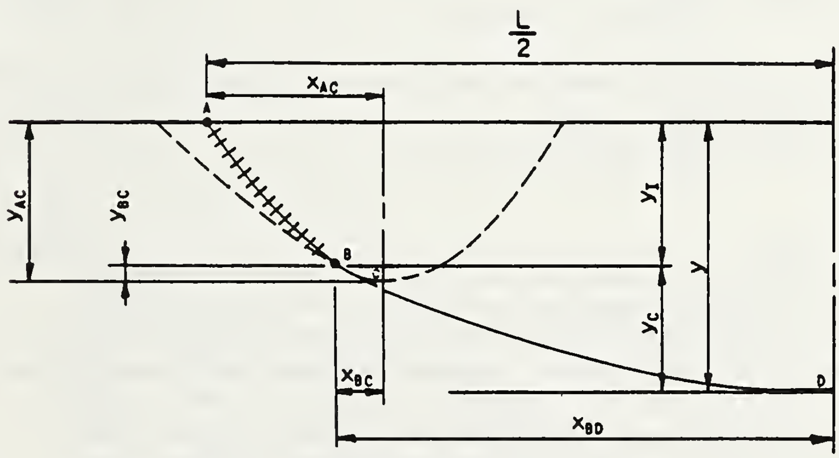
k: NESC constant (from Table IV-12)

e. Calculate or obtain the maximum conductor sag. Methods for this calculation can be found in conductor manufacturers' literature. In some cases the maximum sag may occur during the most severe loading condition. For substation strain buses, the design tension is usually limited to 13,350 newtons (3000 pounds) per conductor under the most severe loading to minimize the size of support structures. These conductor tensions must be coordinated with the support structure designs to ensure compatibility under all loading conditions. The tensions that will occur under unloaded conditions will be considerably less than the maximum.

For light loading conditions where ice loads are not considered, the maximum conductor sag may occur at the highest conductor temperature when the conductor length is at a maximum. For other loading conditions,

sags should be determined for both high conductor temperatures and maximum loading so that adequate clearance from other equipment can be provided.

f. Calculate the suspension insulator effect on conductor sag. For short dead-ended spans, such as substation strain buses, the suspension insulators can have an appreciable effect on span sags. The following procedure can be used to calculate the insulator effect, which is added to the conductor sag for the total bus sag.



$$C_I = \frac{T_C}{W_{IN}} \qquad \text{IV-12}$$

$$C_C = \frac{T_C}{W_C} \qquad \text{IV-13}$$

$$x_{BC} = \frac{C_I}{C_C}\, x_{BD} \text{ (Assume } x_{BD} = \frac{L}{2} - l_{AB}\text{)} \qquad \text{IV-14}$$

$$y_{BC} = C_I \left[\left(\cosh \frac{x_{BC}}{C_I}\right) - 1\right] \qquad \text{IV-15}$$

$$l_{AC} = l_{AB} + C_I \sinh \frac{x_{BC}}{C_I} \qquad \text{IV-16}$$

$$x_{AC} = C_I \sinh^{-1} \frac{l_{AC}}{C_I} \qquad \text{IV-17}$$

$$y_{AC} = C_I \left[\left(\cosh \frac{x_{AC}}{C_I}\right) - 1\right] \qquad \text{IV-18}$$

$$y_I = y_{AC} - y_{BC} \qquad \text{IV-19}$$

$$y = y_I + y_C \qquad \text{IV-20}$$

C_I: insulator catenary constant, in meters (feet)

C_C: conductor catenary constant, in meters (feet)

x_{AC}: horizontal distance from insulator support point to center of insulator catenary, in meters (feet)

x_{BC}: horizontal distance from connection point of insulator string and conductor to center of insulator catenary, in meters (feet)

x_{BD}: horizontal distance from connection point of insulator string and conductor to center of conductor catenary, in meters (feet)

l_{AB}: length of insulator string, in meters (feet)

l_{AC}: arc length from insulator support point to center of insulator catenary, in meters (feet)

y_{AC}: sag from insulator support point to center of insulator catenary, in meters (feet)

y_{BC}: sag from connection point of insulator string and conductor to center of insulator catenary, in meters (feet)

y_I: insulator sag, in meters (feet)

y_C: conductor sag, in meters (feet)

y: total bus sag, including insulators and conductor, in meters (feet)

T_C: horizontal conductor tension, in newtons (pounds)

W_{IN}: insulator string weight, in newtons per meter (pounds per foot)

W_C: conductor weight, in newtons per meter (pounds per foot)

L: span length, in meters (feet)

g. Calculate and chart stringing tensions and corresponding sags for a range of expected conductor temperatures during installation. Base the calculations on the assumed maximum tension that occurs under the most severe conductor loading. To be included in the chart and listed on the installation drawings are span length, tension, and total bus sag for various conductor temperatures. Methods to determine the sags and tensions can be found in conductor manufacturers' literature.

After the conductor sags are calculated, add the suspension insulator sag to the conductor sags to determine the total bus sags as described in Section L2(f) of this chapter.

h. Example Calculation of Bus Conductor Loading

Calculate the total bus conductor loading for the following strain bus:

Span length:	60.96 meters (200 feet)
Voltage:	161 kV
BIL:	750 kV
Conductor size:	795 kcmil 26/7 ACSR
Conductor diameter:	2.81 cm (1.108 in)
Conductor weight:	16.0 N/m (1.094 lb/ft)
NESC loading:	heavy

Ice loading: Select ice thickness from Table IV-12.

$W_I = 0.704\ (d_1^2 - d_2^2)$ $\qquad$ $(W_I = 0.311\ (d_1^2 - d_2^2))$

$W_I = (0.704)\ [(5.35)^2 - (2.81)^2]$ $\qquad$ $(W_I = (0.311)\ [(2.108)^2 - (1.108)^2])$

$W_I = 14.6$ N/m $\qquad$ $(W_I = 1.0$ lb/ft$)$

Wind loading: Select wind pressure from Table IV-12.

$F_W = 0.01\ P_W d_1$ $\qquad$ $(F_W = 0.083\ P_W d_1)$

$F_W = (0.01)(191.5)(5.35)$ $\qquad$ $(F_W = (0.083)(4)(2.108))$

$F_W = 10.2$ N/m $\qquad$ $(F_W = 0.70$ lb/ft$)$

Total bus conductor loading:

$$F_T = [F_W^2 + (W_C + W_I)^2]^{\frac{1}{2}} + k \qquad (F_T = [F_W^2 + (W_C + W_I)^2]^{\frac{1}{2}} + k)$$

$$F_T = [(10.2)^2 + (16.0 + 14.6)^2]^{\frac{1}{2}} + 4.38 \qquad (F_T = [(0.70)^2 + (1.094 + 1.0)^2]^{\frac{1}{2}} + 0.30)$$

$$F_T = 36.6 \text{ N/m} \qquad (F_T = 2.51 \text{ lb/ft})$$

i. Example Calculation of Suspension Insulator Effect on Bus Sag

Calculate the suspension insulator effect on bus sag for the following strain bus:

Span length:	60.96 meters (200 feet)
Voltage:	161 kV
BIL:	750 kV
Conductor size:	795 kcmil 26/7 ACSR
Conductor diameter:	2.81 cm (1.108 in)
Conductor weight:	16.0 N/m (1.094 lb/ft)
Conductor tension:	8896 N (2000 lb)
Number of suspension insulators (from Table IV-5):	10
Length of each insulator:	14.6 cm (5.75 in)
Weight of each insulator:	48.9 N (11.0 lb)

$$C_I = \frac{T_C}{W_{IN}} \qquad \left(C_I = \frac{T_C}{W_{IN}}\right)$$

$$C_I = \frac{\frac{8896}{48.9}}{(14.6)\left(\frac{1}{100}\right)} \qquad \left(C_I = \frac{\frac{2000}{11}}{(5.75)\left(\frac{1}{12}\right)}\right)$$

$$C_I = 26.6 \text{ m} \qquad (C_I\ 87.1 \text{ ft})$$

$$C_C = \frac{T_C}{W_C} \qquad \left(C_C = \frac{T_C}{W_C}\right)$$

$$C_C = \frac{8896}{16} \qquad \left(C_C = \frac{2000}{1.094}\right)$$

$$C_C = 556 \text{ m} \qquad (C_C = 1828 \text{ ft})$$

$$x_{BC} = \frac{C_I}{C_C} x_{BD} \qquad \left(x_{BC} = \frac{C_I}{C_C} x_{BD}\right)$$

$$x_{BC} = \frac{26.6}{556}\left(\frac{60.96}{2} - \frac{(10)(14.6)}{100}\right) \qquad \left(x_{BC} = \frac{87.1}{1828}\left(\frac{200}{2} - \frac{(10)(5.75)}{12}\right)\right)$$

$$x_{BC} = 1.39 \text{ m} \qquad (x_{BC} = 4.54 \text{ ft})$$

$$y_{BC} = C_I \left[\left(\cosh \frac{x_{BC}}{C_I}\right) - 1\right] \qquad \left(y_{BC} = C_I \left[\left(\cosh \frac{x_{BC}}{C_I}\right) - 1\right]\right)$$

$$y_{BC} = (26.6)\left[\left(\cosh \frac{1.39}{26.6}\right) - 1\right] \qquad \left(y_{BC} = (87.1)\left[\left(\cosh \frac{4.54}{87.1}\right) - 1\right]\right.$$

$y_{BC} = 0.0363$ m $\qquad$ ($y_{BC} = 0.118$ ft)

$$l_{AC} = l_{AB} + C_I \sinh \frac{x_{BC}}{C_I}$$ $\qquad$ $$(l_{AC} = l_{AB} + C_I \sinh \frac{x_{BC}}{C_I})$$

$$l_{AC} = (10)\frac{(14.6)}{(100)} + (26.6) \sinh \frac{1.39}{26.6}$$ $\qquad$ $$l_{AC} = (10)\frac{(5.75)}{(12)} + (87.1) \sinh \frac{4.54}{87.1})$$

$l_{AC} = 2.85$ m $\qquad$ ($l_{AC} = 9.33$ ft)

$$x_{AC} = C_I \sinh^{-1} \frac{l_{AC}}{C_I}$$ $\qquad$ $$(x_{AC} = C_I \sinh^{-1} \frac{l_{AC}}{C_I})$$

$$x_{AC} = (26.6) \sinh^{-1} \frac{2.85}{26.6}$$ $\qquad$ $$(x_{AC} = (87.1) \sinh^{-1} \frac{9.33}{87.1})$$

$x_{AC} = 2.84$ m $\qquad$ ($x_{AC} = 9.31$ ft)

$$y_{AC} = C_I \left[\left(\cosh \frac{x_{AC}}{C_I}\right) - 1\right]$$ $\qquad$ $$(y_{AC} = C_I \left[\left(\cosh \frac{x_{AC}}{C_I}\right) - 1\right])$$

$$y_{AC} = (26.6) \left[\left(\cosh \frac{2.84}{26.6}\right) - 1\right]$$ $\qquad$ $$(y_{AC} = (87.1) \left[\left(\cosh \frac{9.31}{87.1}\right) - 1\right]$$

$y_{AC} = 0.152$ m $\qquad$ ($y_{AC} = 0.498$ ft)

$y_I = y_{AC} - y_{BC}$ $\qquad$ ($y_I = y_{AC} - y_{BC}$)

$y_I = 0.152 - 0.0363$ $\qquad$ ($y_I = 0.498 - 0.118$)

$Y_I = 0.116$ m $\qquad$ ($Y_I = 0.38$ ft)

The value calculated for y_I is then added to the conductor sag to determine the total bus sag. Use $2x_{BD}$ as the span length to calculate the conductor sag.

M. APPLICATION OF MOBILE TRANSFORMERS AND SUBSTATIONS

Mobile transformers or mobile substations can be used to provide temporary service during equipment maintenance, construction, emergency, or high load periods. Sufficient mobile units strategically placed can reduce or eliminate the requirements for on-site spare transformers.

Several aspects should be considered in applying mobile transformers or substations. To be considered are:

1. Size and maneuverability of the equipment
2. Installation location and provisions
3. Electrical clearances
4. Primary and secondary connections
5. Grounding
6. Auxiliary system requirements
7. Safety

1. Size and Maneuverability of the Equipment

One of the primary advantages of mobile equipment is its ability to be used at more than one location. To accommodate installation, adequate space must be available to position and connect the equipment at all intended locations. It may be impossible to use larger units in some locations without substantial modifications because of the lack of sufficient space.

Substation entrances and access roads should be evaluated before committing particular equipment to the location in question. Prior planning can save much time and facilitate installation.

2. Installation Location and Provisions

The mobile transformer or substation location should permit primary and secondary connections as short as possible to the permanent substation equipment. It is desirable to utilize bare conductors for the connections. Sometimes, insulated cables can be used where electrical clearances cannot be maintained or where connections are long. The location should permit any required connections to be made quickly and safely without disturbing adjacent equipment. The ease and speed of installation can be influenced by the proximity of energized equipment.

Substations for which mobile equipment has been designated should have provisions for installation of the equipment. The provisions can simply be terminals on permanent substation equipment or buses for connecting the mobile equipment. It may be desirable to include bus extensions and/or disconnect switches in some substations to facilitate the connections, particularly if they may be made while the substation is energized.

If low voltage ac or dc supplies are required, permanent facilities can be provided in the vicinity where the mobile equipment will be positioned. A weatherproof cabinet containing any necessary terminal blocks, switches, or protective devices can be provided for terminating the low voltage circuits. Temporary connections can be made from this cabinet to the control cabinet on the mobile equipment. Connections into the substation alarm system can also be provided in this or another cabinet. Terminal blocks, test switches, indicating lamps, or any other necessary equipment can be located in the cabinet.

Provisions for grounding the equipment can consist of terminals or ground rods connected to the main grounding grid.

3. Electrical Clearances

Maintaining adequate electrical clearances between the mobile equipment, its connections, and other equipment is of prime importance. Installation using bare conductors should not be considered for a location, unless the minimum clearances listed in Tables IV-6 and IV-7 in Section I of this chapter can be maintained. Insulated conductors can be used in some locations if the minimum clearances cannot be maintained.

4. Primary and Secondary Connections

All primary and secondary connections should be as short as possible and should be made with bolted connections. If possible, bare conductors should be used. However, for situations where minimum electrical clearances cannot be maintained or where connections are long, insulated conductors can be employed.

Conductors used should be sized to carry the maximum loads expected without overheating and to sustain anticipated fault currents without damage. They should be checked for sufficient length before connecting either end.

Temporary poles or structures may be required in some locations to facilitate the connections and maintain clearances. It is desirable to store any necessary equipment not part of the mobile unit at the substations, where required.

5. Grounding

Adequate grounding of mobile transformers and substations is extremely important for safe operation. At least two independent connections should be made between the trailer and the ground system. The mobile equipment should be connected to the substation ground grid whenever in close proximity to the substation. In situations where the mobile is located a long distance away from the substation and connection to the substation ground grid is impractical, a separate ground system must be provided.

6. Auxiliary System Requirements

Mobile unit transformers are usually designed for forced-cooled operation. Some units can provide the low voltage necessary for auxiliary equipment operation through the use of an on-board supply transformers and equipment. For units without these provisions, low voltage supplies can be obtained from the substation station service system.

Before the substation station service system is used to supply mobile unit auxilary systems, the voltage(s) required by the auxiliary systems must be checked against those available at the substation for compatibility. The system should also be checked for adequate capacity.

If an external dc supply is necesary for power or control applications, the substation control battery can be used. The system should be checked for proper voltage and adequate capacity prior to utilization.

7. Safety

Unless the mobile equipment is completely contained within another fenced area, a separate fence should be provided to surround the equipment. The fence must provide the same security and protection as would a permanent substation fence. Gates should be provided with adequate locking facilities.

Mobile equipment usually requires some assembly during installation. Barriers and supports may require installation. Some supporting members or braces used to protect the equipment during transit may have to be removed. Assembly and installation should be in strict accordance with the manufacturer's instructions.

The equipment should be positioned on a level site and blocked to prevent movement. Ground slope at the installation location should not exceed the manufacturer's recommendations.

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LEGEND

C_C: Conductor catenary constant

C_I: Insulator catenary constant

D : Centerline-to-centerline spacing of bus conductors

d_1: Outside diameter of bus conductor with ice

d_2: Outside diameter of bus conductor without ice

E : Modulus of elasticity

W_C: Bus conductor weight per unit length

W_I: Ice loading on bus conductor per unit length

W_{IN}: Insulator string weight per unit length

F_{SC}: Short-circuit force on bus conductor per unit length

F_T: Total bus conductor loading per unit length

F_W: Wind loading on bus conductor per unit length

F_B: Maximum desirable bus conductor fiber stress

I : Moment of inertia

i : Short-circuit current

k : NESC conductor loading constant

K_{SC}: Short-circuit force reduction factor

K_{DE}: Multiplying factor for maximum vertical conductor deflection

K_{DM}: Multiplying factor for maximum vertical conductor deflection

K_{SE}: Multiplying factor for maximum bus support spacing

K_{SM}: Multiplying factor for maximum bus support spacing

L : Bus span length

L_M: Maximum bus support spacing

L_S: Conductor length for calculating insulator cantilever strength

Δl: Conductor expansion (final length minus initial length)

l : Initial conductor length

l_{AB}: Length of insulator string

l_{AC}: Arc length from insulator support point to center of insulator catenary

P_W: Wind pressure on projected area of bus conductor

S : Bus conductor section modulus

ΔT: Bus conductor temperature variation (final temperature minus initial temperature)

T_C: Horizontal bus conductor tension

W_S: Minimum insulator cantilever strength

x_{AC}: Horizontal distance from insulator support point to center of insulator catenary

x_{BC}: Horizontal distance from connection point of insulator string and conductor to center of insulator catenary

x_{BD}: Horizontal distance from connection point of insulator string and conductor to center of conductor catenary

y: Total bus sag or deflection

y_{AC}: Sag from insulator support point to center of insulator catenary

y_{BC}: Sag from connection point of insulator string and conductor to center of insulator catenary

y_I: Insulator sag

y_C: Conductor sag

y_{max}: Maximum permissable conductor deflection

α: Coefficient of linear thermal expansion

CHAPTER V - MAJOR EQUIPMENT

A. GENERAL

Major electrical equipment in a substation is generally categorized by longer delivery, manufacture only after receipt of purchase order, custom design to some degree, and much greater per unit cost than minor items such as insulators, bare wire and conduit.

The specification for such equipment is determined not only by its relationship to other equipment in the substation but also by pre-established system conditions and performance requirements. The following sections in this chapter, therefore, deal with the many possible variations in equipment. Procurement of major equipment is usually dependent on a detailed technical specification often developed after consulation with vendors.

Selection of the major equipment requires the utmost consideration. Cost, schedule and performance penalties may be incurred due to improper selection. The design process has great flexibility for change in minor items, but very little can be done in the detail substation design to overcome deficiencies in major equipment selection.

B. POWER TRANSFORMERS

1. General

This section will deal primarily with oil-filled power transformers with nominal primary voltage ratings of 230 kV and below and utilizing one of the following methods of cooling: (1) self-cooled (OA); (2) self-cooled and assisted by forced-air (OA/FA for one stage), (OA/FA/FA for two stages) or (3) self-cooled and assisted by forced-oil and forced-air (OA/FOA for one stage), (OA/FA/FOA or OA/FOA/FOA for two stages). Other methods of cooling are available and are described in ANSI Standard C57.12.00.

Power transformers serve two very important functions in a power system. They transform system voltage from one nominal level to another and must be capable of carrying continuously (within the guidelines of ANSI C57.92) the power flow for their particular location in the system.

Meeting these specific requirements usually results in the power transformer being the largest, heaviest, most complex and costly piece of equipment used in a substation.

Because of their great importance and complexity, power transformers require special care in their application, specification and procurement. This is best accomplished by taking full advantage of applicable industry standards and guides of national organizations such as ANSI, IEEE, NEMA, etc., and REA Bulletin 43-5, "List of Materials Acceptable for Use on Systems of REA Electrification Borrowers."

The following discussion will highlight various aspects of power transformers and provide guidance and recommendations to assist borrowers in obtaining the proper equipment for their systems. Most of this discussion will apply to step-down transformers, especially those not included in the List of Materials. (REA Specification S-4 covers Step-Up Substation Transformers quite thoroughly and should be referred to for those applications).

Standards or guide documents referred to in this bulletin are available from one of the sources listed below:

American National Standards Institute (ANSI), 1430 Broadway, New York, New York 10018.

Institute of Electrical and Electronic Engineers (IEEE), 345 East 47th Street, New York, New York 10017.

National Electrical Manufacturer's Association (NEMA), 155 East 44th Street, New York, New York 10017.

2. Types

Power transformers may be either autotransformers or multiwinding conventional transformers. A three-phase installation may consist of a three-phase unit or three single-phase units. The decision as to what type of transformer to purchase depends on such factors as initial installed cost, operating cost (efficiency), reliability, etc. Three-phase units have greater efficiency, smaller bank size and lower initial cost, making them the most economical. The advantage of the three single-phase units is that it is possible to purchase a spare unit at a much lower cost. The exposure of three phase units to long

outages can be minimized on a system-wide basis when a mobile substation or transformer is available for backup in case of failure.

The kVA ratings with and without auxiliary cooling for various sizes of transformers are covered by the standards, particularly ANSI C57.12.10, Tables 8 and 14 (see Appendix). Transformers larger than those listed in these tables would normally be triple rated or would have provision for the future addition of two stages of cooling equipment to produce a triple rating. For triple rated transformers, some manufacturers use a combination of oil pumps and fans, while others use fans alone to obtain the nameplate forced-cooled ratings. If alternate methods are offered, any cooling preference should become part of the evaluation.

The choice between conventional two- or three-winding transformers and autotransformers involves their basic differences as they may affect the application and cost factors. In general, autotransformers are considered primarily due to cost advantages where the voltage transformation ratio is favorable, up to possibly 3/1. Beyond this ratio, the cost advantage of autotransformers diminishes. Also, autotransformers are wye connected and thus provide only an in-phase angular relationship between primary and secondary voltages.

Other advantages of autotransformers are smaller physical size, lighter weight, lower regulation (voltage drop in transformer), smaller exciting currents (easier no-load switching) and lower losses. The main disadvantages of autotransformers are lower reactance (impedance), more complex design problems and adverse affect on ground relaying. These problems can usually be resolved.

3. Ratings

a. Capacity

The selection of substation transformer kVA capacity should be based on an acceptable up-to-date engineering study. The selection should consider the effects of load cycle, load factor and ambient temperature as described in ANSI C57.92, "Guide for Loading Oil-Immersed Distribution and Power Transformers (for 55°C average winding temperature rise)" and NEMA, TR98 (for 65°C average winding temperature rise).

Since cooling efficiency decreases with increase in altitude, the transformer manufacturer must be informed when the transformer will be operated at an elevation above 1,000 meters (3300 feet) so that an adequate cooling system is provided. Refer to ANSI Standard C57.12.00, Paragraph 2.5 (see Appendix) for the effect of altitude on temperature rise. Also, multi-winding transformers with loads on various windings at different power factors have higher load losses and may require additional cooling capacity.

In addition to selecting a transformer capable of satisfying the basic capacity requirements it is also desirable to give due consideration to inventory and standardization; the objective being to simplify spare parts, testing, maintenance and unit sparing problems.

b. Temperatures

Normal transformer design is based on ambient temperatures of 40°C maximum, 30°C average over 24 hours, and -20°C minimum. Abnormal ambient temperatures should be made known to the manufacturer at the time of purchase since they usually require modifications in the design of the transformer.

c. Voltage

Nominal voltage ratings of a transformer are selected to conform to system voltage conditions. ANSI Standard C57.12.10, Tables 2, 3, 4 and 5 (see Appendix) lists standard voltages and taps through 138 kV. In accordance with standards, transformers should not be subjected to operating voltages above 105 percent of any rated secondary tap when operating loaded to nameplate kVA rating and above 110 percent of rated secondary tap when operating at no-load.

d. Basic Insulation Levels (BILs)

ANSI Standard C57.12.00, Tables 4, 7, 8, 11 and 12 (see Appendix), lists basic insulation levels commonly used for various system voltages. Continuous improvements over the years in the protective margins provided by surge arresters have enabled users to select reduced insulation levels for transformers, at appreciable cost reductions, without sacrificing reliability.

Any selection of a transformer with reduced BIL is a user responsibility and requires knowledge of certain system characteristics.

On effectively grounded systems, a reduced BIL of one step below full basic insulation level normally can be specified for transformers with nominal ratings of 115 kV and above. Further reductions may require an insulation coordination study to ensure that adequate margin is maintained between transformer insulation strength and the protective level of protective equipment.

e. Loading

A transformer can supply a load well beyond its nameplate rating for various periods of time, with or without affecting its normal life, depending on several factors related to temperature conditions in the transformer. These are discussed in REA Bulletin 161-22, "Application Guide for Transformers."

4. Taps

No-load and/or load taps (LTC) can be obtained on power transformers. The addition of no-load taps in the primary of a substation transformer maked it possible to adapt the transformer to a range (usually a 10 percent overall range of which 5 percent is above nominal and 5 percent below nominal) of supply voltages. Of course, the transformers must be deenergized when the manual no-load tap position is changed. All taps should have full capacity ratings. The individual tap voltages should be as specified in REA Specifications S-3 and S-4, where applicable. Otherwise, they should be according to ANSI C57.12.10, Tables 4 and 5 (see Appendix).

Any decision to use load tap changing transformers should be based on a careful analysis of the particular voltage requirements of the loads served and consideration of the advantages and disadvantages, including costs, of alternatives such as separate voltage regulators. REA Bulletin 161-22, "Application Guide for Transformers," lists several important considerations concerning load tap changing transformers. When load tap changing transformers are specified, they shall comply with the requirements of ANSI C57.12.00, C57.12.10 and C57.12.30.

5. Impedance

Transformer impedance affects transformer voltage regulation, efficiency and magnitude of through-short circuit currents. Both regulation and efficiency are generally improved with lower impedance. However, these desirable results must be viewed along with higher through-fault currents permissible with a lower impedance.

Higher load side fault currents can be potentially damaging to the transformer and may also require higher fault current ratings of load side equipment at increased cost. Prudent compromises are thus often required in specifying transformer impedances.

Where through-fault currents are not a significant factor, it is generally desirable to specify as low an impedance as possible that will not result in increased transformer cost. Normal impedance ranges are listed by manufacturers, and cost penalties apply when these are exceeded. The standards permit manufacturing tolerances of $\pm$ 7.5 percent for two-winding transformers and $\pm$ 10.0 for multiwinding transformers and autotransformers. These are important to remember if transformer paralleling is being considered. Normal impedances for various voltage ratings are given in ANSI Standard C57.12.10, Para. 6, Table 7 (see Appendix). Distribution substation transformers (500 kVA or smaller) should be specified with standard impedances where possible. These impedances are sufficient to make the transformer self protecting under any secondary faults.

6. Phase Relation

Proper phase relationships between the various winding voltages are extremely important in transformer application. These must be selected to fit existing or planned conditions in the particular system.

Standard single-phase substation transformers are built with subtractive polarity. The polarity of a three-phase transformer is fixed by its connections between phases and by relative location of leads. A standard delta-wye or wye-delta, three phase, step-down transformer will result in the high side voltages leading their respective low side voltages by 30 degrees. An installation of three single-phase transformers can be connected to accomplish this same relationship.

Autotransformers are connected wye-wye, and no phase angle exists between the high and low side voltages. This may preclude the use of autotransformers, in some cases, even when they are otherwise preferred.

Attention should also be given to the proper physical orientation of transformers within the substation and to their connections in order to assure that the proper phasing is obtained on all buses. Standard bushing arrangement on a three-phase transformer, when viewed from the low voltage side, is from left to right H_0 (when required), H_1, H_2 and H_3 on the high voltage side and X_0 (when required), X_1, X_2 and X_3 on the low voltage side. If a tertiary or third winding is provided, the bushing arrangement is Y_1, Y_2 and Y_3 left to right when viewed from the side nearest these bushings.

Refer to ANSI C57.12.70 for transformer terminal markings and connections.

7. <u>Parallel Operation of Transformers</u>

In most cases, the purchase of two smaller size transformers, to be operated in parallel in one circuit, in lieu of one full size transformer, is not recommended. Two transformers will cost more than a single transformer of equivalent capacity; their combined losses are higher, and they require a more elaborate and expensive substation structure to accommodate them. However, where a situation exists for possible parallel operation, such as where continuity of at least partial service in event of failure of one unit is of great importance, the transformers should be individually fused and the following guidelines considered.

Any two or more transformers can be operated in parallel, provided: their impedances are in the same order of magnitude when considered on their own kVA base; their voltage taps and voltage ratios are essentially the same; and their polarity and phase voltage displacement are or can be made alike.

Equal impedances will permit proportionate sharing of the load between transformers. If not equal, the load will be divided in inverse proportion to the magnitude of the impedances. This condition is satisfactory within reasonable limits, as determined by requirements, and may be of little consequence where the larger of two transformers has the lower impedance and will carry more than its

proportionate share of the load. However, if the smaller unit has the lower impedance, it will carry more than its share of load and may even become severely overloaded, while the larger unit still has available capacity. This is demonstrated in the following:

a. Condition I - Larger Transformer Has the Smaller Impedance

Two transformers T1 and T2 are operating in parallel. T1 is rated 10 mva with an impedance of 10 percent. T2 is rated 25 mva with an impedance of 7 percent. On a common 100 mva base, impedance of T1 is 100 percent and impedance of T2 is 28 percent.

Power flow divides inversely with the relative impedances on a common base. Assuming a total power flow of 30 mva, T1 would carry 6.6 mva and T2 would carry 23.4 mva, both within their ratings.

The power flow distribution is obtained by solving two simultaneous equations, where P1 and P2 represent the power flows through T1 and T2, respectively, and Z_{100} is
the impedance on a 100 mva base.

Equation 1 $\quad P1 + P2 = 30 \text{ MVA}$

Equation 2 $\quad \frac{P1}{P2} = \frac{Z_{100} \text{ (of T2)}}{Z_{100} \text{ (of T1)}}$

b. Condition II - Smaller Transformer Has the Smaller Impedance

Same as Condition I, except T1 has an impedance of 7 percent and T2 an impedance of 10 percent. On a 100 mva base, impedance of T1 is 70 percent and impedance of T2 is 40 percent.

T1 would carry 10.9 mva and T2 would carry 10.1 mva. T1 is clearly overloaded, whereas T2 has capacity to spare.

c. Condition III - Both Transformers Have Equal Impedances - Preferred Condition

Same as Condition I, except both T1 and T2 have equal impedances on their own base of, say, 8 percent. On a 100 mva base, T1 has an impedance of 80 percent and T2 has an impedance of 32 percent. T1 would carry 8.6 mva and T2 would carry 21.4 mva. Each transformer is carrying its correct share in proportion to its mva rating.

From an impedance standpoint, it has generally been accepted that transformers can be paralleled successfully if the actual or nameplate impedance of one does not differ by more than 7-1/2 percent from the actual or nameplate impedance of the other. For example, a transformer having an impedance of 6 percent can be paired with a transformer having an impedance anywhere between 5.55 percent (.925 x 6 percent) and 6.45 percent (1.075 x 6 percent).

Equal tap voltages, or voltage ratios, will permit each of the paralleled transformers to operate as if it were isolated. But unequal tap voltages will create a circulating current flowing forward through the unit having the higher voltage and in a reverse or leading direction through the unit with the lower voltage. This condition is limited only by the series impedance of the two transformers in the current circulation circuit and by the difference in voltage causing the current flow. This condition can be very severe and must be closely analyzed whenever such operation is contemplated. The condition is most severe when the transformers are not carrying load. It usually is modified sufficiently when load is being carried, and voltage regulation due to load so modifies the voltage difference as to reduce the circulating current to an insignificant level.

Where paralleled transformers are equipped with load tap changers and line drop compensators, paralleling control schemes should be incorporated into the LTC controls. Schemes that may be evaluated include: 1. Negative Reactance Method, 2. Step by Step Method, 3. Out of Step Switch Method, 4. Cross Current Compensation Method.

8. Dielectric Requirements

A transformer in service may be exposed to a variety of dielectric stresses. Lightning impulses may reach the

terminals of the transformer because of direct hits or, more likely, in the form of traveling waves coming in over connecting lines. Such traveling waves are produced when the connecting lines are exposed to lightning strokes.

Direct hits are practically impossible where adequate direct stroke protection is provided over the substation in the form of ground wires and/or masts. The magnitude of traveling wave impulses reaching the transformer depends on: the initial magnitude of the strokes; the distance the wave must travel; transmission line characteristics, such as surge impedance, insulation level and type of ground wire protection; transformer characteristics and protective characteristics of surge protective devices provided. How well the transformer can withstand any impulse voltages reaching it depends on the condition of the insulation at the time of the impulse. Basic insulation levels can be verified by impulse tests. Most large transformers receive impulse tests prior to shipment from the factory.

Normal line energization and deenergization or power circuit breaker operations during system faults produce switching surges that travel down the conductors to the connected transformers. Switching surges generally present no particular problem to transformers rated 230 kV and below. Switching surge withstand capability of a transformer is approximately 83 percent of its BIL. Where justified, factory switching surge tests may be applied to verify switching surge withstand capability.

Properly applied surge arresters are very effective in limiting the magnitude of both impulse and switching surge voltages reaching the transformer to levels below their withstand capabilities. Reduced transformer BIL levels are often possible, at appreciable cost reduction, while still maintaining adequate protective margins. The section on surge arresters contains additional information on the subject.

Transformers may be exposed to abnormal power frequency voltages during system fault conditions. Single phase-to-ground faults produce abnormal voltages to ground on the unfaulted phases. The amount that these voltages increase above normal depends on how solidly the system is grounded. With adequate BILs and surge arrester ratings, these temporary abnormal voltages should present no difficulty for the transformer.

External porcelain insulation on a transformer is designed to withstand voltages to which it may be subjected under varied atmospheric conditions. Severe atmospheric contamination may require increased bushing BILs, increased porcelain creep distances, special porcelain treatment or washing procedures. Local experience under similar conditions is usually the best guide as to the most practical solution.

Standard transformer external insulation is based on applications below 1,000 meters (3300 feet). Above 1,000 meters, the lower air density offers less voltage withstand capability, and the external insulation level must be derated. Normal ratings are decreased approximately 10 percent for each 1,000 meter increase in elevation above 1,000 meters. See ANSI Standard C76.1, Outdoor Apparatus Bushings, Table 3.2.1(c) (see Appendix) for standard derating factors. Equipment of a suitably higher rating should be chosen if derating at high altitudes is to be avoided.

9. Short Circuit Requirements

Excessive failures of substation transformers due to through fault currents have been a matter of great concern to the industry. The use of larger transformers and the increases in system fault current have contributed to the cause of failures, but it is also probable that inadequacies in transformer design and manufacture have been a contributing factor. Borrowers and their engineers should be aware of this problem and should take appropriate measures to safequard their interests in purchases of power transformers.

a. Background Information

The current edition of The American National Standards for Transformers, ANSI C57.12, provides that transformers withstand a through fault current of not more than 25 times normal full load current for two seconds without failure, with lower withstand requirements for longer times. On the surface, this may appear to assure adequate withstand strength. However, there is no requirement that the manufacturer test the transformer or demonstrate in any way that the transformer can meet this requirement. Furthermore, the standard is not specific as to whether the transformer

must be able to withstand one or an infinite number of through faults. This is particularly important, since it is well recognized that a transformer may withstand one through fault test, yet fail on subsequent shots.

Because of this deficiency in the existing standard requirements, a proposal for a new test code for short-circuit testing is under consideration by industry standardizing groups. In brief, the proposed test code requires the application of six short circuits at maximum current, two of which would result in maximum asymmetry of the fault current (i.e., a current equal to two times the crest value of the maximum symmetrical current decreased by the decrement factor of the transformer winding). The transformer should show no damage after this test as indicated by measurements and visual inspections. For a complete description of the test refer to ANSI C57.12.90a, Power Transformer Short-Circuit Strength Requirements and Test Code.

Assuming that the test code is adopted by the industry, the user must still decide whether to require this test in the purchase specifications. It appears that laboratory tests in the United States would be feasible on two-winding transformers on sizes only up to about 50,000 kVA. Larger sizes conceivably could be tested in the field by the purchaser, but the feasibility of doing so on an operating system is questionable. The laboratory test is fairly costly, and shipping costs to and from the laboratory test facility must be added. The extra shipping and handling would also subject the transformer to a greater risk of transportation shock damage and human error.

b. Recommendations

Single-phase transformers 10,000 kVA (OA) and smaller, rated 138 kV and below, and three-phase transformers 30,000 kVA (OA) and smaller, rated 138 kV and below, are included in REA Bulletin 43-5, List of Materials Acceptable for Use on Systems of REA Electrification Borrowers. Borrowers need not require short-circuit tests for transformers in this category. REA will either request manufacturers to conduct short-circuit tests on any new transformer design proposed for listing or will request evidence that the transformer

design has had a history of successful experience in service. The borrower should not specify unusual taps or impedance in the purchase specification unless absolutely necessary. Such requirements may cause design changes that will affect mechanical strength and introduce uncertainties in the ability of the transformer to withstand short-circuit currents.

Specifications for transformers not included in the List of Materials* should include requirements for short-circuit strength. The manufacturer should be required to demonstrate this strength either directly through previous short-circuit testing of a similar unit or indirectly by a history of successful field experience.

It should be recognized that short-circuit testing will not be feasible on the larger sizes of transformers because of the limitations of existing laboratory facilities. Hence, successful experience will be the principal means for measuring the adequacy of short-circuit strength of these transformers. In this respect, it is recommended that experience be accepted as a demonstration that the transformer design has adequate short-circuit strength when transformers with core and coils identical in all respects to the transformer covered by the specifications have amassed a total of at least 20 transformer years of experience without major failure attributable to design defects.

Where the manufacturer has not built units identical to the transformer covered by the specification, or the experience record is less than 20 transformer

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*Transformers not included in REA Bulletin 43-5 List of Materials:

(1) All autotransformers

(2) All transformers having three or more windings

(3) Single-phase transformers rated greater than 10,000 kVA (QA) or 138 kV

(4) Three-phase transformers rated greater than 30,000 kVA (QA) or 138 kV

c. <u>Recommended Specification for Short-Circuit Strength</u>

It is recommended that the following be incorporated in all purchase specifications for power transformers not included in the List of Materials:

"Without limiting in any way any obligation of the Bidder under this agreement, the Bidder shall demonstrate to the satisfaction of the Owner that the transformer proposed to be furnished under this specification shall have sufficient mechanical strength to withstand without failure all through fault currents. The Bidder shall demonstrate that the transformers meet this requirement by one of the following methods:

(1) Certified test data showing that a transformer with a core and coil identical in design and construction and identical or similar with respect to kVA capacity, kV ratings, BIL, impedance and voltage taps has been tested under maximum short-circuit conditions without failure. A description of the test code under which the transformer was tested for short-circuit strength will be provided by the Bidder to the Owner.

(2) A history of successful experience with transformers of identical or similar ratings, design and construction. The Bidder shall list all transformers in service with core and coils that are essentially identical in design, construction and manufacture to the transformer covered by this specification and shall provide information on the date of installation, location, and failures, if any. Where such transformers have not been built or the cumulative service record is less than 20 transformer years, a list of transformers in service that represent the closest approximation to the transformer covered by this specification shall be submitted. The information submitted shall be representative of the total experience of the manufacturer with the design of the transformer to be furnished and shall include the dates of installation (or shipment, if not installed), the ratings of

the transformers and a list of failures and causes of failures if any have been experienced."

Autotransformers or conventional multiwinding transformers often have special application and design requirements. In such cases, it will be important to provide system short circuit information indicating the most severe short circuit condition that can exist at the terminals of each transformer winding, and any specific impedance requirements.

10. Cooling Equipment

Most of the smaller substation power transformers on rural systems are the oil-immersed, self-cooled (OA) type. In these types of transformers, the oil transfers the heat from the core and coils to the tank wall or cooling tubes, where it passes to the surrounding air. Temperature differences in the oil cause the oil to circulate by convection through the tubes. Adequate air flow is essential to satisfactory operation.

On larger transformers, this cooling process can be accelerated by various methods, namely: using forced air (FA) from fans over the cooling tubes, by using oil pumps to circulate the oil, or by a combination of forced air and forced oil. These forced cooling methods increase the transformer cost but permit a dramatic increase in kVA capacity. Both methods can be automatically controlled in one or two steps from either top oil temperatures or winding temperature or both. Forced cooling methods are usually effective in reducing costs of the larger transformer sizes.

Where any type of forced cooling is relied upon, it is essential that attention be given to adequate operational reliability of the pumps and fans. This involves consideration of redundancy in the power supply to the pumps and fans and to individual or group overload protection and disconnecting means. Also, hot spot and top oil temperature devices can be used to alarm for abnormal cooling indications. The temperature limits should be specified so as to adequately protect the unit but not to limit its overload capability. Suggested alarm limits are:

	55°C Insulation	65°C Insulation
Hottest Spot Temperature	95°C	105°C
Top Oil Temperature	70°C	80°C

The cooling tubes or heat exchangers on large transformers should be specified for easy removal or isolation from the transformer for repairs. In this case, shutoff valves and bolted flanges are provided at the inlet and outlet of each heat exchanger. Transformers below a range of 10,000 kVA, three-phase, and 5,000 kVA, single-phase, usually have nonremovable cooling tubes. These kVA sizes will vary between manufacturers.

11. Oil and Oil Preservation Equipment

Transformer oil must be kept free from contact with outside contaminants always present in the atmosphere. On smaller substation transformers, the tank is completely sealed with a layer of dry air or nitrogen left above the oil to accommodate expansion and contraction of the oil.

Several methods of oil preservation (see Figure V-1) are commonly used on larger size transformers including: a sealed tank with a positive pressure inert gas layer maintained above the oil by means of a permanently connected tank of nitrogen gas; a tank completely filled with oil but connected to a raised tank or oil conservator, which maintains a positive oil pressure in the main tank and provides a place for expansion and contraction of the oil. Various types of conservator tank designs are available, depending on the manufacturer. These include a divided expansion tank with two sections and the flexible diaphragm conservator tank. Some manufacturers use a balloon bag within the conservator tank as a variation of the flexible diaphragm.

The choice of oil preservation system is mostly a matter of personal preference and experience. All have been successfully used for many years. Regardless of the method used, periodic tests must be made of the oil and oil perservation system to assure that oil quality is being maintained.

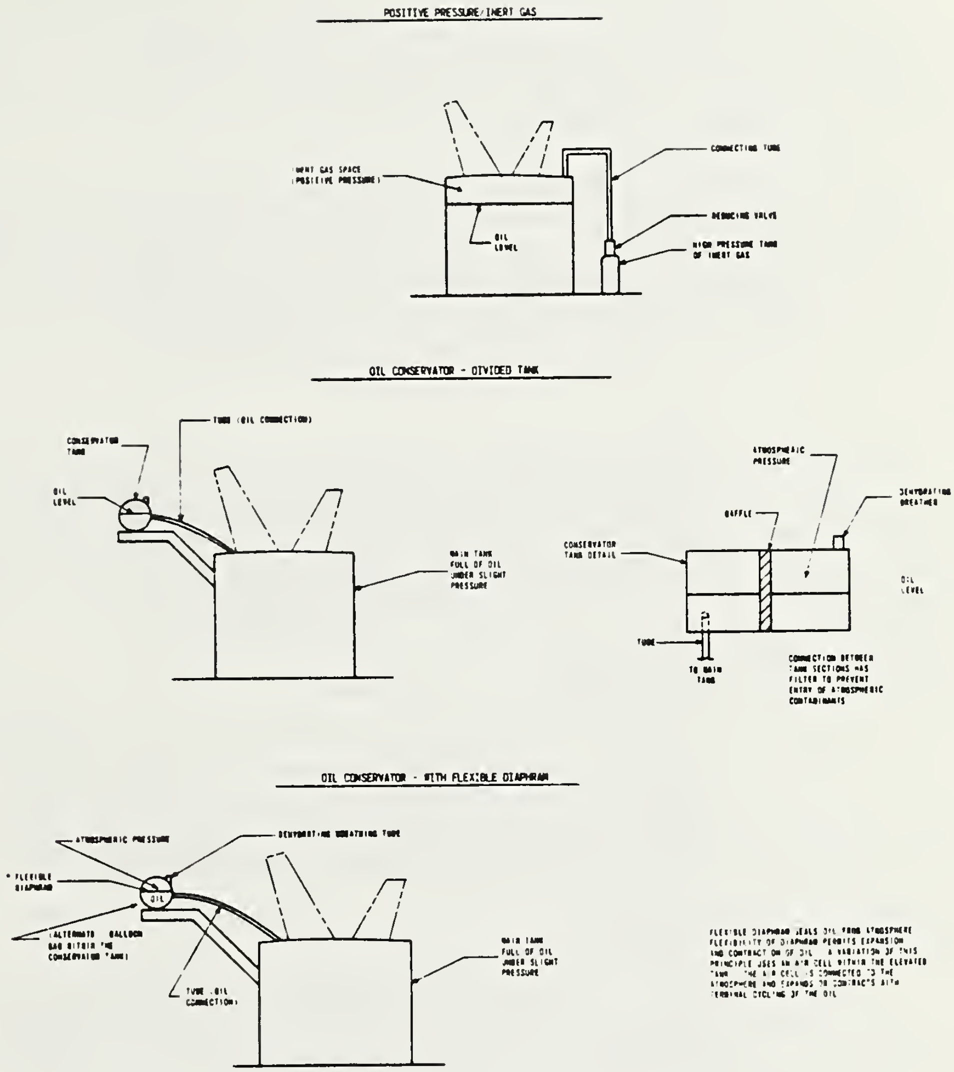

FIGURE V-1 METHODS OF OIL PRESERVATION

12. Audible Sound

Sound (noise) levels produced by transformers, as well as other substation equipment, are becoming a matter of increasing concern to the public. The fact that rural substations are more often located away from congested areas reduces the possibility of complaints. However, this is partially offset by the lower ambient sound levels common in rural areas.

In some areas, noise ordinances may dictate what is required. The designer should accordingly be familiar with the problems and their solutions. A thorough treatment of the subject is beyond the scope of this bulletin, but some practical guidelines will be presented here. Any values given should be treated as approximations.

a. Site

Sound is usually transmitted radially from the source. Avoid sites that have a direct line of sight to possible areas of complaints. A particularly poor selection would be a low level site with residential areas on the surrounding higher ground.

b. Landscape

Natural or artificial barriers such as mounds or shrubbery positioned between the sound source and the public are desirable. Although these have little effect on sound levels, they can reduce the psychological impact of a new substation and prevent complaints.

c. Distance

Sound levels are attenuated with distance. Approximately a 6 dB(A) reduction can be obtained with each doubling of the distance between source and point of measurement.

d. Sound Levels

Standard sound levels for transformers are listed in NEMA TR1. Reduced sound level transformers increase the transformer cost approximately 1-1/2 percent for each dB(A) reduction from these NEMA standard levels. Transformer sound levels tend to increase with BIL, kVA and number of stages of cooling. A practical

limit in designing special low sound level transformers is approximately a 12 dB reduction where forced cooling is required. Greater reductions require expensive measures, such as double wall tanks.

Required sound levels in dBs (based on the ANSI weighting network "A" response or dB(A) scale) will vary from one situation to another. Levels sometimes prescribed in ordinances may be approximately 45 dB at night and 55 dB in daytime. These levels may apply only to a potential source of complaint or at the substation boundaries. For comparison, a NEMA standard designed 20,000 kVA two-winding substation transformer with 350 kV BIL and first stage of auxiliary cooling would have an average sound level of 72 dB. (References: See References 1. and 2.).

e. Barriers

Sound barriers located near the transformer can be considered in special cases (especially at existing installations) as a means of reducing noise levels in the vicinity. Barriers can produce a maximum reduction of approximately 20 dB. A total enclosure can produce a 40 dB reduction. For partial barriers, a reduction of 15 dB is a practical maximum. The effect of the barriers on transformer cooling must also be considered.

13. Tank

In most cases, the manufacturer's standard provisions related to the transformer tank will meet requirements for filling and draining, oil sampling, handling, internal inspection, etc. Any special requirements or preferences should be considered at the time specifications are written and their possible extra cost evaluated. Some items to consider are: preferred location of heat exchangers, preferred location and height of cabinets and other accessories above transformer base, construction of terminal boards, paint color, provisions for future additions, etc.

14. Accessories

Various accessories are available for use with power transformers. Many of these are standard items normally supplied with the basic transformer while others are special items available at extra cost. Items supplied as standard are listed in ANSI Standards. Some accessories

not furnished as standard items but that may be desires are: special bushings, current transformers, bushing capacitance potential taps, bushing potential device(s), auxiliary power provisions, special relays, special terminals, spare parts, etc.

15. Electrical Tests and Measurements

a. Dielectric Tests

Dielectric tests consist of a variety of tests each performed to prove a certain characteristic of the transformer insulation structure. (See ANSI Standards C57.90 and C57.98 for complete information on tests.) Dielectric tests are generally specified only on the larger sizes of transformers or on smaller transformers used in especially important applications. Most manufacturers charge for these tests. Table V-1 at the end of Paragraph 15 provides guidelines for specifying dielectric tests.

(1) The full wave impulse test (1.2 x 50μs wave), because of its relatively long duration, causes major oscillations to develop in the winding and consequently stresses not only turn-to-turn and section-to-section insulation throughout the winding but also develops relatively high voltages, compared to power frequency stresses, across large portions of the winding and between the winding and ground (core and adjacent windings). This test is designed to simulate a lightning stroke.

(2) The chopped wave impulse test (similar to the full wave test but 15 percent higher and chopped on the tail in about 3 μs or less), because of its shorter duration, does not allow the major oscillations to develop as fully, and generally does not produce as high voltages across large portions of the winding or between the winding and ground. However, because of its greater amplitude, it produces high voltages at the line end of the winding and, because of the rapid change of voltage following flashover of the test gap, it produces higher turn-to-turn and section-to-section stresses. It is designed to simulate a lightning stroke truncated by a flashover on an adjacent portion of the insulation system.

(3) The front-of-wave impulse test (similar to the chopped wave test but chopped on the front and with a much steeper front) is still shorter in duration and produces still lower winding-to-ground voltages deep within the winding. Near the line end, however, its greater amplitude produces higher voltages from winding to ground, and this, combined with the rapid change of voltage on the front and following flashover, produces a high turn-to-turn and section-to-section voltages near the line end of the winding.

(4) The switching surge test is related to the other impulse tests, but has a much longer wave front and tail. This slow wave fully penetrates the windings and stresses all parts of the insulation structure.

(5) An applied voltage test measures the ability of the transformer to survive at normal frequency overvoltage. It also determines the increase in exciting current.

(6) An induced voltage test measures the insulation strength between turns in the winding and the insulation strength of barriers and other major insulation between phases. During this test, a partial discharge (corona) test can be conducted to determine presence, inception and extinction levels of partial discharges that may be damaging to the insulation structure and eventually lead to failure.

The partial discharge (corona) test consists of measuring the one megahertz (by agreement between manufacturers and users) portion of any pulses produced within the transformer during low frequency tests and that show up at the transformer terminals. The low frequency tests are usually performed using 120 to 240 Hertz voltages. The magnitude of the partial discharge readings are expressed in microvolts.

Most manufacturers take the measurements from each HV bushing capacitance tap, when these taps are available. A calibration procedure is used to convert the tap readings to an equivalent value at the bushing terminal.

b. Measurements (Electrical)

Measurements that produce data required for operation of the transformer include resistance, core and conductor losses, excitation current, impedance, ratio and regulation temperature rise, insulation power factor, polarity and phase relation, etc. Consult ANSI C57.12.90 for detailed information regarding these test measurements.

TABLE V-1

Guidelines For Specification of Dielectric Tests on Power Transformers Rated 230 kV & Below

	10,000 kVA(OA) or less Mfr's Quality Assurance Only*	Above 10,000 kVA(OA) Purchaser's Specification**
Reduced Full Wave	Yes	Yes
Chopped Wave (2 shots)	Yes	Yes
Full Wave	Yes	Yes
Low Frequency Tests	Yes	Yes
Partial Discharge (Internal Corona)	Usually None	Yes

*Manufacturer's practices regarding quality assurance tests will vary from one manufacturer to another. When these tests are performed, no official report is provided to the customer.

**Purchaser's Specification should specify that the dielectric tests shall be performed in accordance with ANSI Standards. An official manufacturer's report should be required.

16. Shipment

Several shipping considerations are important. During shipping, the transformer may be subjected to its most severe test due to rough handling. Acceleration measuring devices (impact recorder) mounted on the transformer during shipment will help to determine whether the transformer may have been subjected to excessive forces. In any case, a thorough inspection should be made of the interior of the transformer to determine whether movement of the core and coils has taken place or whether evidence of any other damage exists.

Larger size transformers are shipped without oil but sealed with either a blanket of nitrogen gas or dry air. The method used often varies with the transformer manufacturer. Either method is considered satisfactory, provided proper safety precautions are taken and warning signs are exhibited to deter a person from entering an unsafe tank before it has been purged with proper amounts of air or oxygen.

It is good practice to provide the manufacturer with all necessary information regarding the situation at the final destination. This will enable shipment to be made in the most convenient manner. Sometimes it is important for the transformer to be positioned a particular way on the final carrier to facilitate unloading at the site.

17. Warranty

In general, transformer manufacturers warrant their product to be free of defects in workmanship and material for a specified period. In the event of a defect, the manufacturer may elect to correct the problem at his option either by repairing defective part or parts or by supplying a repaired or replacement part or parts. Under terms of normal warranty, the manufacturer assumes no responsibility for disassembly or reassembly of the equipment or return transportation from field to factory and back to field.

Since warranties are subject to many variables, the purchaser is cautioned to exercise care in review and evaluation of each. Warranty periods vary from 1 to 5 years or more. Special warranties are available, at some increase in purchase price, that extend warranty period; include cost of removing failed transformer from field, return to factory, repair, return to field, reinstallation in field; etc.

18. Specifications

Purchase specifications should be based on standards of national organizations such as ANSI, IEEE, NEMA, etc. However, when the desired power transformer is included in REA Bulletin 43-5, List of Materials Acceptable for Use on Systems of REA Electrification Borrowers, specification need only cover such details as voltage, kVA ratings, optional tests, features or accessories that are offered by the manufacturer and considered necessary or desirable. The basic requirements for transformers in the List of Materials are given in the ANSI Standards C57 series and should not be included in the purchase specification. The latest List of Materials includes step-down power transformers in the following sizes and voltage ratings:

	Primary Voltage Rating	Capacity, kVA
Single Phase	138 kV and below	10,000 kVA(OA) and below
Three Phase	138 kV and below	30,000 kVA(OA) and below

Distribution substation transformers shall be in accordance with REA Specifications for Step-Down Substation Transformers, Specification No. S-3, where applicable.

Generating station substation transformers shall be in accordance with REA Specifications for Step-Up Substation Transformers, Specification No. S-4, where applicable.

Purchase specifications for transformers that are not included on the List of Materials should be detailed enough to provide reasonable assurance that the transformer will be suitable for its intended use. In general the specification should be based on functional and operational requirements rather than construction and design requirements, since the latter are properly the responsibility of the manufacturer. It is very important that users review the "usual" and "unusual" operating conditions listed in "General Requirements Standards" such as C57.12.00 and C57.12.01. Any unusual or special operating or environmental condition should be made known to the manufacturer.

It is recommended that the purchase specifications be modeled on or checked against the requirements of ANSI Guide for Preparation of Specifications for Large Power

Transformers, With or Without Load Tap Changing, C57.97. In addition, it is recommended that a special requirement for short circuit current strength be included such as given in this chapter under Power Transformers, Item 9, Short Circuit Requirements. The manufacturer's standard design should be accepted, and standard sizes, ratings, taps and accessories should be specified unless there is a good reason for doing otherwise.

To assist in the evaluation of transformers being offered in a particular case, it is desirable to include in the request for bids the method for evaluation of transformer losses. This should be patterned after the REA Bulletin entitled "Evaluation of Power Transformer Losses." This information will also assist the manufacturer in his efforts to offer the type of transformer desired.

ANSI, IEEE OR NEMA STANDARDS OR GUIDES APPLICABLE TO SUBSTATION POWER TRANSFORMERS

GENERAL DOCUMENTS

ANSI C57.12.70, Terminal Markings and Connections for Distribution and Power Transformers

ANSI C57.12.80, Transformer Terminology

ANSI C57.12.90a Draft, Distribution and Power Transformer Short-Circuit Test Code (IEEE 262A)

ANSI C57.98, Guide for Transformer Impulse Tests (IEEE 93-1968)

NEMA TR 1, Transformers, Regulators and Reactors

GENERAL DOCUMENTS - FOR LIQUID-IMMERSED TRANSFORMERS

ANSI C57.12.00, General Requirements for Distribution, Power, and Regulating Transformers (IEEE 462-1973)

ANSI C57.12.90, Test Code for Distribution, Power, and Regulating Transformers (IEEE 262-1973)

ANSI C57.93, Guide for the Installation and Maintenance of Oil-Immersed Transformers

ANSI C57.101, Guide for Transformer Installation (IEEE 283-1968)

ANSI C59.131, Guide for Acceptance and Maintenance of Insulating Oil in Equipment (IEEE 64)

POWER TRANSFORMER DOCUMENTS

ANSI C57.12.10, Requirements for Transformers 230000 Volts and Below 833/958 through 8333/10417 kVA, Single-Phase; and 750/862 through 60000/80000/100000 kVA, Three Phase

ANSI C57.12.30, Requirements for Load-Tap-Changing Transformers 230000 Volts and Below, 3750/4687 through 60000/80000/100000 kVA Three-Phase

POWER TRANSFORMER DOCUMENTS (Cont'd)

ANSI C57.92, Guide for Loading Oil-Immersed Distribution and Power Transformers

Note: The latest revision of any standard or guide document should be consulted.

REFERENCES

1. Audible Noise Reduction by R. S. Pedersen of
San Diego Gas & Electric Company,
Transmission and Distribution November 1956

2. Transformer Audible Noise by M. W. Schulz,
Member IEEE, General Electric Company,
Schenectady, New York
Presented as part of a IEEE Tutorial Course on
"Application of Distribution and Power Transformers"
organized by W. J. McNutt, Fellow, IEEE,
General Electric Company, Pittsfield, Massachusetts

Numerous articles referenced at end of above article.

APPENDIX

TO

POWER TRANSFORMERS

Table 2
Maximum Allowable Average Temperature* of Cooling Air for Carrying Rated kVA

Method of Cooling Apparatus	1000 Meters (3300 Feet)	2000 Meters (6600 Feet)	3000 Meters (9900 Feet)	4000 Meters (13 200 Feet)
		Degrees C		
Oil-Immersed Self-Cooled	30	28	25	23
Oil-Immersed Forced-Air-Cooled	30	26	23	20
Oil-Immersed Forced-Oil-Cooled with Oil-to-Air Cooler	30	26	23	20
Dry-Type Self-Cooled				
(1) 55°C Rise	30	27	24	21
(2) 80°C Rise	30	26	22	18
(3) 150°C Rise	30	22	15	7
Dry-Type Forced-Air-Cooled				
(1) 55°C Rise	30	24	19	14
(2) 80°C Rise	30	22	14	6
(3) 150°C Rise	30	15	0	−15

* Recommended calculation of average temperature is described in Footnote 2.

Ref. C57.12.00

2.5 Effect of Altitude on Temperature Rise. The effect of the decreased air density due to high altitude is to increase the temperature rise of transformers which are dependent upon air for the dissipation of heat losses.

2.5.1 *Operation at Rated kVA.* Transformers can be operated at rated kVA at altitudes greater than 1000 meters (3300 feet) without exceeding temperature limits provided the average temperature of the cooling air does not exceed the values of Table 2 for the respective altitudes.

2.5.2 *Operation at Less than Rated kVA.* Transformers can be operated at altitudes greater than 1000 meters (3300 feet) without exceeding temperature limits provided the load to be carried is reduced below rating by the percentages given in Table 3 for each 100 meters (330 feet) that the altitude is above 1000 meters (3300 feet).

Table 3
Rated kVA Correction Factors for Altitudes Greater Than 1000 Meters (3300 Feet)

Types of Cooling	Correction Factor Percent
Oil-immersed self-cooled	0.4
Oil-immersed water-cooled	0.0
Oil-immersed forced-air-cooled	0.5
Oil-immersed forced-oil-cooled with oil-to-air cooler	0.5
Oil-immersed forced-oil-cooled with oil-to-water cooler	0.0
Dry-type self-cooled	0.3
Dry-type forced-air-cooled	0.5

Ref. C57.12.00

Table 4
Insulation Classes and Dielectric Tests
for Oil-Immersed Transformers

Insulation Class* (kV)	Low-Frequency Test (kV rms)	BIL and Full Wave (kV Crest)	Chopped Wave (kV Crest)	Chopped Wave Min Time to Flashover (μs)
(Col 1)	(Col 2)	(Col 3)	(Col 4)	(Col 5)
1.2A	10	30	36	1
1.2	10	45	54	1.5
2.5A	15	45	54	1.5
2.5	15	60	69	1.5
5.0A	19	60	69	1.5
5.0	19	75	88	1.6
8.7A	26	75	88	1.6
8.7	26	95	110	1.8
15A	34	95	110	1.8
15	34	110	130	2
18	40	125	145	2.25
25	50	150	175	3
34.5	70	200	230	3
46	95	250	290	3
60	120	300	345	3
69	140	350	400	3
92	185	450	520	3
115	230	550	630	3
138	275	650	750	3
161	325	750	865	3
180	360	825	950	3
196	395	900	1035	3
215	430	975	1120	3
230	460	1050	1210	3
260	520	1175	1350	3
287	575	1300	1500	3
315	630	1425	1640	3
345	690	1550	1780	3
375	750	1675	1925	3
400	800	1800	2070	3
430	860	1925	2220	3
460	920	2050	2360	3
490	980	2175	2500	3
520	1040	2300	2650	3
545	1090	2425	2800	3

*The letter "A" under Insulation Class refers specifically to distribution levels for distribution transformers.

NOTES:

(1) Section 4.1.3 for regulating taps.

(2) Single-phase distribution and power transformers and regulating transformers for voltage ratings between terminals of 8.7 kV and below are designed for both Y and Δ connection and are insulated for the test voltages corresponding to the Y connection so that a single line of transformers serves for the Y and Δ applications. The test voltages for such transformers when operated Δ connected are, therefore, one step higher than needed for their voltage rating.

(3) Y-connected transformers for operation with neutral solidly grounded or grounded through an impedance may have reduced insulation at the neutral as specified in 4.2.

(4) For series windings in transformers such as regulating transformers, the test values to ground shall be determined by the insulation class of the series windings rather than by the rated voltage between terminals.

Ref. C57.12.00

Table 7
Basic Impulse Insulation Levels
Usually Associated with Nominal System Voltages
for Oil-Immersed Power Transformers

			10 000 kVA and Below	
Nominal System Voltage (kV)	BIL (kV)	Low-Frequency Test to Other Windings and Ground (kV rms)	BIL (kV)	Low-Frequency Test to Other Windings and Ground (kV rms)
(Col 1)	(Col 2)	(Col 3)	(Col 4)*	(Col 5)*
1.2	45	10	30	10
2.4	60	15	45	15
4.8	75	19	60	19
8.32	95	26	75	26
14.4	110	34	95	34
23	150	50	—	—
34.5	200	70	—	—
46	250	95	—	—
60	300	120	—	—
69	350	140	—	—

*If specified, the values in Columns 4 and 5 apply only to power transformers, 10 000 kVA and smaller, with winding voltages 14.4 kV and below.

NOTES:

(1) If specified, lower insulation levels may be used in power transformers, 10 000 kVA and smaller, when suitable protection can be provided.

(2) For higher system voltages it is common to use insulation dependent on the degree of protection which can be obtained. For example, in 230 kV systems, BIL's (with corresponding low-frequency tests) of 1050, 900, 825, 750 and 650 kV have been used.

(3) See Section 4.1.3 for regulating taps.

(4) Single-phase distribution and power transformers and regulating transformers for voltage ratings between terminals of 8.7 kV and below are designed for both Y and Δ connection and are insulated for the test voltages corresponding to the Y connection, so that a single line of transformers serves for the Y and Δ applications. The test voltages for such transformers when operated Δ connected are, therefore, one step higher than needed for their voltage rating.

(5) Y-connected transformers for operation with neutral solidly grounded or grounded through an impedance may have reduced insulation at the neutral as specified in Section 4.2.

(6) For series windings in transformers such as regulating transformers, the test values to ground shall be determined by the insulation class of the series windings rather than by the rated voltage between terminals.

Ref. C57.12.00

Table 8
Insulation Classes Applying to Nominal System Voltages Not Appearing in Tables 6 and 7

Nominal System Voltage (Volts)	Distribution Transformers BIL (kV)	Distribution Transformers Insulation Class (kV)	Power Transformers BIL (kV)	Power Transformers Insulation Class (kV)
(Col 1)	(Col 2)	(Col 3)*	(Col 4)	(Col 5)
120	30	1.2A	45	1.2
120/240	30	1.2A	45	1.2
120/208Y	30	1.2A	45	1.2
240	30	1.2A	45	1.2
480	30	1.2A	45	1.2
600	30	1.2A	45	1.2
2400/4160Y	60	5A	75	5
6900	75	8.7A	95	8.7
7200	75	8.7A	95	8.7
4800/8320Y	75	8.7A	95	8.7
12 000	95	15A	110	15
7200/12 470Y	95	15A	110	15
7620/13 200Y	95	15A	110	15
13 200	95	15A	110	15
27 600	200	34.5	200	34.5

*The letter "A" under Insulation Class refers specifically to distribution levels for distribution transformers.

NOTES:

(1) Except for the first and second lines, which indicate the usual single-phase two- or three-wire systems, the figures in Column 1 refer to three-phase systems.

(2) See Section 4.1.3 for regulating taps.

(3) Single-phase distribution and power transformers for voltage ratings between terminals of 8.7 kV and below are designed for both Y and Δ connection and are insulated for the test voltages corresponding to the Y connection, so that a single line of transformers serves for the Y and Δ applications. The test voltages for such transformers when operated Δ connected are, therefore, one step higher than needed for their voltage rating.

(4) Y-connected transformers for operation with neutral solidly grounded or grounded through an impedance may have reduced insulation at the neutral as specified in Section 4.2.

(5) For series windings in transformers such as regulating transformers, the test values to ground shall be determined by the insulation class of the series windings rather than by the rated voltage between terminals.

(6) If specified, power transformers, 10 000 kVA and smaller and with winding voltages 14.4 kV and below, may use lower insulation levels when suitable protection is provided. See Table 7.

Ref. C57.12.00

Table 11
Switching Surge Tests for
Oil-Immersed Transformers When Specified

Insulation Class (kV)	BIL (kV)	Switching Surge Test (kV Crest)
(Col 1)	(Col 2)	(Col 3)
1.2	45	20*
2.5	60	35*
5.0	75	38*
8.7	95	55*
15	110	75*
18	125	80*
25	150	100*
34.5	200	140*
46	250	190*
60	300	235*
69	350	280*
92	450	375
115	550	460
138	650	540
161	750	620
180	825	685
196	900	745
215	975	810
230	1050	870
260	1175	975
287	1300	1080
315	1425	1180
345	1550	1290
375	1675	1390
400	1800	1500
430	1925	1600
460	2050	1700
490	2175	1800
520	2300	1900
545	2425	2010

*These voltage values are not intended as test voltage values on high-voltage windings, but are to be used for limiting the induced switching surge voltage in low-voltage windings when a high-voltage winding is tested. Test values for these insulation classes are to be determined.

Ref. C57.12.00

Table 12
Minimum Insulation Class at Neutral

Insulation Class at Line Terminals of Winding (kV)*	Minimum Insulation Class at Neutral, (kV)		
	Grounded Solidly or Through Current Transformer†	Grounded Through Regulating Transformer	Grounded Through Ground Fault Neutralizer or Isolated but Impulse Protected
(Col 1)	(Col 2)	(Col 3)	(Col 4)
1.2	1.2	1.2	1.2
2.5	2.5	2.5	2.5
5.0	5.0	5.0	5.0
8.7	8.7	8.7	8.7
15	8.7	8.7	8.7
25	8.7	8.7	15
34.5	8.7	8.7	25
46	15	15	34.5
69	15	15	46

*For higher line terminal insulation classes the insulation class at the neutral shall be specified to conform with service requirements, but in no case shall be less than 15 kV.

†For transformers rated 500 kVA and smaller, a ground stud may be furnished.

Ref. C57.12.00

Table 2
Range of Voltage and Kilovolt-Ampere Ratings for Single-Phase Transformers

High-Voltage Ratings (V)	Low-Voltage Ratings (V)					
	480	2400/4160Y, 2520/4360Y, 4800/8320Y, 5040/8720Y	6900/11 950Y, 7200/12 470Y, 7560/13 090Y, 7620/13 200Y, 7970/13 800Y	12 000, 12 600, 13 200, 14 400	14 400/24 940Y	34 500, 19 920/34 500Y, 20 920/36 230Y
	Kilovolt-Ampere Ratings (KVA)					
2400/4160Y	833					
4800/8320Y	833					
6900/11 950Y, 7200/12 470Y, 7620/13 200Y, 12 000, 13 200, 13 800	833, 1250	833–2500				
22 900	833, 1250	833–2500	833–2500			
34 400	833, 1250	833–2500	833–3333	833–3333		
43 800*	833, 1250	833–2500	833–8333	833–8333		
67 000		833–2500	833–8333	833–8333		
115 000		2500	2500–8333	2500–8333	2500–8333	2500–8333
138 000		2500	2500–8333	2500–8333	2500–8333	2500–8333

NOTES:
(1) All voltages are Δ unless otherwise indicated.
(2) Kilovolt-ampere ratings separated by a dash indicate that all the intervening ratings listed in Table 1 are included. Kilovolt-ampere ratings separated by a comma indicate that only those listed are included.

*Nonpreferred voltage [American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz), C84.1-1977].

Ref. C57.12.10

Table 3

Range of Voltage and Kilovolt-Ampere Ratings for Three-Phase Transformers

High-Voltage Ratings (V)	Low-Voltage Ratings (V)						
	480Y/277, 480	2400, 2520, 4160Y/2400, 4360Y/2520	4800, 5040, 8320Y/4800, 8720Y/5040	6900, 7200, 7560, 12 470Y/7200, 13 090Y/7560, 13 260Y/7620, 13 800Y/7970	12 000, 12 600, 13 200, 14 400	24 940GrdY/14 400	34 500, 34 500GrdY/19 920, 36 230GrdY/20 920
	Kilovolt-Ampere Ratings (kVA)						
2400	750–1500						
4160, 4800	750–1500						
6900, 7200	750–2500	1000–3750					
12 000, 13 200, 13 800	750–2500	1000–7500					
22 900		1000–7500	1000–10 000	1000–10 000			
34 400		1000–7500	1000–10 000	1000–10 000	1000–10 000		
43 800*		1500–7500	1500–10 000	1500–10 000	1500–10 000		
67 000		1500–7500	1500–10 000	1500–10 000	1500–10 000		
115 000		5000–7500	5000–10 000	5000–10 000	5000–10 000	5000–10 000	5000–10 000
138 000		5000–7500	5000–10 000	5000–10 000	5000–10 000	5000–10 000	5000–10 000

NOTES:

(1) All voltages are Δ unless otherwise indicated.

(2) Kilovolt-ampere ratings separated by a dash indicate that all the intervening ratings listed in Table 1 are included

*Nonpreferred voltage [American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz), C84.1-1977].

Ref. C57.12.10

Table 4
Insulation Characteristics and High-Voltage Taps for Single-Phase Transformers

High-Voltage Ratings (V)	Basic Lightning Impulse Insulation Level (kV)	High-Voltage Taps (V)
2400/4160Y	75	2520/2460/2340/2280 4360Y/4260Y/4055Y/3950Y
4800/8320Y	95	5040/4920/4680/4560 8720Y/8520Y/8110Y/7900Y
6900/11 950Y	110	7245/7070/6730/6555 12 550Y/12 250Y/11 650Y/11 350Y
7200/12 470Y	110	7560/7380/7020/6840 13 090Y/12 780Y/12 160Y/11 850Y
7620/13 200Y	110	8000/7810/7430/7240 13 860Y/13 530Y/12 870Y/12 540Y
12 000	110	12 600/12 300/11 700/11 400
13 200	110	13 860/13 530/12 870/12 540
13 800	110	14 400/14 100/13 500/13 200
22 900	150	24 100/23 500/22 300/21 700
34 400	200	36 200/35 300/33 500/32 600
43 800*	250	46 200/45 000/42 600/41 400
67 000	350	70 600/68 800/65 200/63 400
115 000	450	120 750/117 875/112 125/109 250
138 000	550	144 900/141 450/134 550/131 100

NOTE: All voltages are Δ unless otherwise indicated.

*Nonpreferred voltage [American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz), C84.1-1977].

Table 5
Insulation Characteristics and High-Voltage Taps for Three-Phase Transformers

High-Voltage Ratings (V)	Basic Lightning Impulse Insulation Level (kV)	High-Voltage Taps (V)
2400	60	2520/2460/2340/2280
4160	75	4360/4260/4055/3950
4800	75	5040/4920/4680/4560
6900	95	7245/7070/6730/6555
7200	95	7560/7380/7020/6840
12 000	110	12 600/12 300/11 700/11 400
13 200	110	13 860/13 530/12 870/12 540
13 800	110	14 400/14 100/13 500/13 200
22 900	150	24 100/23 500/22 300/21 700
34 400	200	36 200/35 300/33 500/32 600
43 800*	250	46 200/45 000/42 600/41 400
67 000	350	70 600/68 800/65 200/63 400
115 000	450	120 750/117 875/112 125/109 250
138 000	550	144 900/141 450/134 550/131 100

NOTE: All voltages are Δ.

*Nonpreferred voltage [American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz), C84.1-1977].

Ref. C57.12.10

Table 8
Self-Cooled (OA) and
Forced-Air-Cooled (FA) Ratings

Single-Phase (kVA)		Three-Phase (kVA)	
OA	FA	OA	FA
833	958	750	862
1 250	1 437	1 000	1 150
1 667	1 917	1 500	1 725
2 500	3 125	2 000	2 300
3 333	4 167	2 500	3 125
5 000	6 250	3 750	4 687
6 667	8 333	5 000	6 250
8 333	10 417	7 500	9 375
		10 000	12 500

Table 14
Self-Cooled (OA), Forced-Cooled First-Stage,
and Forced-Cooled Second-Stage Kilovolt-Ampere
Ratings for Three-Phase Transformers

OA	First-Stage	Second Stage
12 000	16 000	20 000
15 000	20 000	25 000
20 000	26 667	33 333
25 000	33 333	41 667
30 000	40 000	50 000
37 500	50 000	62 500
50 000	66 667	83 333
60 000	80 000	100 000

6. Impedance Voltage

6.1 Percent Impedance Voltage. The percent impedance voltage at the self-cooled rating as measured on the rated voltage connection shall be in accordance with Table 7.

6.2 Tolerance on Impedance Voltage. The tolerance shall be as specified in American National Standard C57.12.00-1973 (IEEE Std 462-1973), including Supplement C57.12.00a-1977 (IEEE Std 462a-1977).

6.2.1 Percent Departure of Impedance Voltage on a Tap. The percent departure of tested impedance voltage on any tap from the tested impedance voltage at rated voltage shall not be greater than the total tap voltage range expressed as a percentage of the rated voltage.

Table 7
Percent Impedance Voltages

High-Voltage BIL (kV)	Low Voltage 480 V	Low Voltage, 2400 V and Above
60 - 150	6.75	6.5
200	7.25	7.0
250	7.75	7.5
350	—	8.0
450	—	8.5
550	—	9.0

TABLE 3.2.1(c)

DIELECTRIC STRENGTH CORRECTION FACTORS

Altitude(Ft.)	Altitude Correction Factor
3,300	1.00
5,000	0.95
10,000	0.80

Reference: ANSI C76.1

C. POWER CIRCUIT BREAKERS

1. General

a. Scope

By definition, a circuit breaker is a device that closes and interrupts (opens) an electric circuit between separable contacts under both load and fault conditions, as prescribed in the C37 series of American National Standards (ANSI). This discussion will be limited to circuit breakers rated 1000 volts and above.

b. Prerequisites to Specification

The application of circuit breakers involves consideration of the intended function, expected results, benefits to the electric system and characteristics of both the circuit breakers and the electric system. In some instances, protective devices of lesser capability and flexibility, such as fuses, circuit switchers, reclosers, etc., may be more desirable or preferred over more complex and costly circuit breakers.

Fuses are desirable for transformer protection at any location where they are adequate for the thermal load and short circuit conditions at that location because of their lower cost and smaller space requirements compared to other devices. They are also desirable for their ease of coordination with circuit breakers and relays at other locations on the electric system. Fuses can also be applied as temporary maintenance by-pass protection to permit maintenance of circuit breakers. Fuses are also used extensively for sectionalization and branch circuit protection in distribution systems.

Circuit switchers are less costly than circuit breakers and can be applied in much the same way as circuit breakers, subject to limitations in interrupting capability, with the same type of relay control as circuit breakers. They can be substituted for fuses in transformer bank protection to detect low voltage side faults that fuses may not be able to detect. This detection would utilize relay intelligence from the low voltage side. Circuit switchers also provide excellent capacitor bank switching and protection.

In outlying areas of moderate short circuit capacity, they can often be substituted for circuit breakers. They can be mounted similarly to air-break switches on the substation structure and thus require little or no additional space.

Reclosers are completely self-contained and provide excellent distribution circuit exit and feeder protection. Their ratings are adequate for both load and short circuit on more distribution circuits and overlap the ratings of more costly circuit breakers. Their operation is faster than most circuit breakers, and their sequence of open and close operations is very flexible. Reclosers are available in both single phase and three phase ratings so that they are very useful and adaptable for the entire distribution system at locations where reclosing operation is required.

Writing of specifications and selection of power circuit breakers and similar devices should be preceded by electric system studies to determine the parameters of application and operation that must be satisfied. These include load flow, short circuit, transient voltage, coordination and protection studies.

c. Specification - General Requirements

Power circuit breakers are not included in REA's "List of Materials" because of the numerous types, ratings and applications. Therefore, for each application, a detailed specification is necessary. A functional specification describing the circuit breaker rating and control, electric system characteristics and any special requirements is preferred to one describing design and construction details. "American National Standard Guide Specifications for ac High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis and a Total Current Basis," C37.12, can be used directly as a model or checklist for the purchase specification. A manufacturer's standard design and construction should normally be considered acceptable.

It is recommended that those persons responsible for preparing power circuit breaker specifications become familiar with (1) the entire series of ANSI Standards C37 covering ratings, testing, applications, specifications, etc., (2) each specific application and proposed

installation and (3) each prospective supplier's product line of circuit breakers.

2. Types of Circuit Breakers

Breakers are usually classified as "dead tank" or "live tank" construction. "Dead tank" means that the circuit breaker tank and all accessories are maintained at ground potential, and the external source and load connections are made through conventional bushings. "Live tank" means that the metal and porcelain housing containing the interrupting mechanism is mounted on an insulating porcelain column and is therefore at line potential. This column, besides serving as an insulating support, also may act as an access for the operating rod or linkage and, in the case of air circuit breakers, acts as an air supply duct.

In addition to classification as "live tank" or "dead tank" construction, circuit breakers are also classified in terms of interrupting media. Although availability of different breaker designs is closely related to the "state of the art" at any particular time, Table V-2 indicates the known current availability of breaker types.

TABLE V-2

TYPES OF CIRCUIT BREAKERS

	Availability vs Interrupting Media			
Outdoor	Oil	Air	Gas	Vac
Dead Tank				
Single Tank	X	-	-	X
3 Tank	X	X	X	X
Live Tank				
3 Tank	"Minimum" Oil Type	X	X	?
Indoor				
Dead Tank	X Limited	X	X	X

No general guidelines can be drawn for the application of these various types of circuit breakers. Each user must determine the ratings of circuit breakers that he requires and then select a type of circuit breaker acceptable to him in regard to rating, performance expectations, compatibility with planned or existing substation configuration and his ability to install, operate and maintain the circuit breaker. Cost may also be an important consideration in the final selection.

Most, but not all, domestic circuit breakers in outdoor substations of 2.4 through 230 kV utilize oil as the insulating dielectric and interrupt load and fault currents under oil. These are of "dead tank" construction.

Oil breakers are available in 2.4 to 69 kV ratings in single tanks and in 34.5 to 230 kV ratings in three (individual pole) tanks. The overlap of either single or three tank construction in the range of 34.5 to 69 kV is due to the various specific load and interrupting currents, temperature rise, limiting tank pressures and other design criteria for the final selection of a circuit breaker for a given application.

Oil circuit breakers through 69 kV are mounted in structural angle frames, and most of them have facilities for lowering the tank to expose the interrupting mechanism for inspection and maintenance. Where facilities for untanking are not included with the breaker, a separate tank lifter is required. At least one tank lifter should be provided at each substation.

Above 69 kV, the three individual pole tanks are base mounted and usually welded to heavy H-beams that serve as a common base to form a very rigid unit. Access to the interrupting mechanisms of these circuit breakers is gained through manholes in the sides of the tanks.

Most circuit breakers other than oil, usually 121 kV and above, are of live tank construction. However, there are some dead tank type units in limited use for indoor and outdoor mini-substation construction and one known type also in limited use for outdoor bulk substation use.

3. Ratings

The rating of a circuit breaker is a summary of its characteristics that identifies its application on an electric

system, its performance capabilities and its adaptability. This summary of characteristics is given principally in terms of voltages, currents and time as described in the rating tables, in the ANSI C37 Standards and in the following paragraphs. Table 4A of C37.06 is included here for reference in the following discussion (see Appendix).

a. Voltage

Voltage characteristics are defined in terms of rms nominal, rms rated maximum, rated voltage range factor and insulation strength crest kV.

(1) Nominal Voltage

Nominal voltage, also known as voltage class, was formerly used to identify the electric system voltage on which a particular circuit breaker was intended for application and to relate short circuit current and short circuit MVA interrupting capabilities. Nominal voltage is now used only as a reference.

(2) Rated Maximum Voltage

Rated maximum voltage is the maximum voltage for which the circuit breaker is designed and is also the upper limit for operation on an electric system. It is based on "American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz)," ANSI C84.1. It is the prime operating voltage reference and relates the rated short circuit interrupting current and short circuit interrupting MVA or energy handling capabilities.

(3) Rated Voltage Range Factor

Rated voltage range factor, designated as "K," defines the lower limit of operating voltage at which the required symmetrical and asymmetrical current interrupting capabilities vary in inverse proportion to the operating voltage.

"K" is the ratio of rated maximum voltage to this lower limit of operating voltage. The rated maximum voltage either divided by K or multiplied by the reciprocal, 1/K, will produce

the lower limit of operating voltage. Referring to ANSI C37.06, Table 4A (see Appendix) for 115 through 700 kV circuit breakers, the voltage range factor is 1.0. This limits the maximum interrupting current capability at voltages lower than rated voltage to a value no greater than the interrupting current capability at rated maximum voltage.

For 2.4 through 69 kV circuit breakers, ANSI C37.06, Tables 1-4 show a rated maximum voltage related to an interrupting MVA rating, from which the rated interrupting current is obtained. These circuit breakers all have a voltage range factor greater than 1.0, which permits operation at lower than rated voltage and a maximum interrupting current of K times rated interrupting current as described above. The MVA interrupting rating remains unchanged for these operating conditions.

Example (ANSI C37.06, Table 3 in Appendix)

Circuit breaker rated 69 kV, 2500 MVA, 19 KA interrupting capacity, maximum operating voltage 72.5 kV, voltage range factor K = 1.21.

Calculate maximum interrupting current,

$I = (19\ \text{KA})(1.21) = 23\ \text{KA}.$

Lower operating voltage limit,

$E = 72.5/1.21 = 60\ \text{kV}.$

(4) Insulation Withstand Test Voltages

Schedule of dielectric tests for power circuit breakers includes values for low frequency and impulse. These values are fixed and are related directly to rated maximum voltage of breakers. Dielectric test valves for outdoor ac high-voltage power circuit breakers are shown in Table 5 of ANSI C37.06 (see Appendix).

b. Current

Current characteristics are defined as follows:

(1) Rated Continuous Current

The rated continuous current of a circuit breaker is the designated limit of current in rms amperes at rated frequency that it is required to carry continuously without exceeding any of the limitations designated in ANSI C37.04.4.1 and ANSI C37.04.4.2.

(2) Rated Short-Circuit Current

The rated short-circuit current of a circuit breaker is the highest value of the symmetrical component of the polyphase or line-to-line short-circuit current in rms amperes measured from the envelope of the current wave at the instant of primary arcing contact separation that the circuit breaker is required to interrupt at rated maximum voltage and on the standard operating duty. It also establishes, by fixed ratios as defined in ANSI C37.04-4.5.2, the highest currents that the breaker is required to close and latch against, to carry, and to interrupt.

The relationship of rated short-circuit current to the other required capabilities is illustrated in ANSI C37.04, Figs. 1 and 2 (see Appendix).

(3) Related Required Capabilities

In addition to the current ratings defined above, symmetrically rated circuit breakers have related current capabilities. These related capabilities, discussed in detail in ANSI C37.04, are essentially as follows:

(a) Maximum symmetrical interrupting capability = K times rated short circuit current.

These related required capabilities are based on a relay time of one-half cycle, but may be used with any permissible tripping delay.

(b) Required symmetrical interrupting capability of a circuit breaker for polyphase and line-to-line faults is the highest value of the symmetrical component of the short-circuit current in rms amperes at the instant of primary arcing contact separation that the circuit breaker shall be required to interrupt at a specified operating voltage on the standard operating duty and irrespective of the direct current component of the total short-circuit current. The numerical value at an operating voltage between 1/K times rated maximum voltage and rated maximum voltage shall be determined by the following formula:

Required symmetrical interrupting capability =
(rated short-circuit current) times

$$\left(\frac{\text{rated maximum voltage}}{\text{operating voltage}}\right)$$

In no case shall the required symmetrical interrupting capability exceed K times rated short-circuit current.

(c) Required asymmetrical interrupting capability of a circuit breaker for polyphase and line-to-line faults is the highest value of the total short-circuit current in rms amperes at the instant of primary arcing contact separation that the breaker shall be required to interrupt at a specified operating voltage and on the standard operating duty.

The numerical value shall be equal to the product of a ratio S, specified below and illustrated in ANSI C37.04, Figure 2 (see Appendix), times the required symmetrical interrupting capability of the breaker determined for the operating voltage. The values of S shall be 1.4, 1.3, 1.2, 1.1, or 1.0 for breakers having primary arcing contact parting times of 1, 1.5, 2, 3, 4 or more cycles, respectively. The values of S for primary arcing contact parting times

bewteen those given above shall be determined by linear interpolation. The primary arcing contact parting time shall be considered equal to the sum of one-half cycle (present practical minimum tripping delay) plus the lesser of:

> The actual opening time of the particular breaker,

or

> 1.0, 1.5, 2.5, or 3.5 cycles for breakers having a rated interrupting time of 2, 3, 5, or 8 cycles, respectively.

(d) Required symmetrical and asymmetrical interrupting capability of a circuit breaker for single line-to-ground faults shall be 1.15 times the corresponding values specified for polyphase and line-to-line faults. In no case are the capabilities for single line-to-ground faults required to exceed K times the symmetrical interrupting capability (that is, K times rated short-circuit current) and K times the asymmetrical interrupting capability, respectively, determined at rated maximum voltage.

(e) Three second short time capability = K times rated short circuit current.

(f) Closing and latching capability = 1.6 times rated short circuit capability.

c. Interrupting Time

The rated interrupting time of a circuit breaker is the maximum permissible interval between the energizing of the trip circuit at rated control voltage and the interruption of the main circuit in all poles on an opening operation, when interrupting a current within the required interrupting capabilities and equal to 25 percent or more of the required asymmetrical interrupting capability at rated maximum voltage. At duties below 25 percent of the required asymmetrical interrupting capability at rated maximum voltage, the

circuit must be interrupted, but the time required for interruption may be greater than the rated interrupting time by as much as 50 percent for 5 and 8 cycle breakers and 1 cycle for 3 cycle breakers. For breakers equipped with resistors, the interrupting time of the resistor current may be longer. The interrupting time for a close-open operation at a specified duty should not exceed the rated interrupting time by more than 1 cycle for 5 and 8 cycle breakers and one-half cycle for 3 cycle breakers. When time is expressed in cycles, it should be on a 60 Hertz basis.

d. Rated Permissible Tripping Delay

The rated permissible tripping delay of a circuit breaker is Y seconds and is the maximum value of time for which the circuit breaker is required to carry K times rated short-circuit current after closing on this current and before interrupting. For values, see American National Standard C37.06.

e. Other Factors Affecting Rating

The factors noted above form the basis of rating breakers complying with C37.04. Other factors that may affect breaker capability include duty cycle, transient recovery voltage, reactive component of load, etc. These are discussed in detail in C37.04.

In particular, the duty cycle of the circuit breaker must be considered in its application. The duty is the short-circuit current required to be interrupted, closed upon, etc. The cycle is a predetermined sequence of closing and opening operations.

The standard duty cycle to which circuit breaker ratings are related is one closing plus one opening operation, followed by a 15 second waiting period, followed by a second closing and a second opening operation (CO + 15 Sec + CO). This duty cycle permits application of the circuit breaker at 100 percent of its rating. Numerous other operating cycles and time intervals can be used. If the number of operating cycles is greater and/or the time intervals are shorter than the standard duty cycle, derating of the breaker interrupting capability is necessary according to principles and procedures given in C37.04 and C37.07.

4. Operating Mechanisms

The operating mechanism of a circuit breaker must be designed to ensure positive or definite opening of the circuit breaker, and circuit interruption must occur whether the tripping or opening signal is received with the circuit breaker fully closed or in any partially closed position. The operating mechanism must also be capable of closing, reclosing and latching closed the circuit breaker against the short circuit current shown in the rating tables (Sec. 3).

Operating mechanisms can be provided with or for multiple-pole or single pole operation or tripping of the circuit breaker. The term "operation" is intended to cover tripping (opening), closing and reclosing of the circuit breaker. Most circuit breakers in the United States utilize multiple-pole (three-pole) operation to serve and protect their entire service area by simultaneous opening or closing of their three poles (phases). For certain applications, such as distribution areas served at a three-phase voltage but branching into single phase circuits, single pole operation is often desirable to interrupt single phase faults on one phase and to maintain service to the remaining two phases.

Operating mechanisms are designed to have the closing function in a ready-to-close condition upon application of a closing signal. Simultaneous with the closing, the tripping function is placed in a ready-to-trip condition by electrical, mechanical or both electrical and mechanical facilities in the operating mechanism. At the end of the previous closing operation, the closing function is again placed in a ready-to-close condition. This interaction of closing and tripping facilities permits any planned number of sequential closing and tripping actions to be performed.

The operating mechanism must perform one complete closing operation including automatic cutoff of the closing power circuit after the initiating control device has been operated either manually or automatically and the first seal-in device in the control scheme has responded, even though the contacts of the initiating control device might be opened before the closing operation has been completed. Furthermore, a closing operation must not be performed at a control voltage lower than the minimum control voltage at which successful tripping can be performed. Most circuit breakers use shunt (voltage) trip coils that must

be capable of tripping the circuit breaker when any voltage in the control voltage range is applied, even if the trip coil plunger is away from its normal maximum force position to the extent that it is in contact with the actuating trigger of the tripping system.

Other tripping solenoids include those operated by current from bushing or separate current transformers and those operated by a capacitor trip device discharge into the trip coil. Refer to Table V-3 for ac and dc control, tripping and closing voltages and voltage ranges.

The operating mechanism should incorporate a number of features specifically for maintenance and assembly operations. The mechanism must have provisons that safeguard maintenance personnel from unintended operation. This is usually accomplished via fuse pullouts, permissive switches or locking pins. Provisions for slowly closing the breaker to align the moving contacts is required. This is usually accomplished with a separate jacking device purchased with the breaker.

Operating mechanisms should be equipped with operation counters. Compressors should be equipped with elapsed running time meters. These two features are important to an effective maintenance program.

a. <u>Solenoid Operating Mechanisms</u>

(1) Voltage (ac and dc) operated solenoids were used almost entirely on all circuit breakers in the past. They were effective but relatively slow compared to present operating methods. They also required a large capacity power supply (transformer or battery) because of their heavy current (ampere) demand, particularly on large, high voltage circuit breakers. Solenoids are still used on some smaller circuit breakers where their lower operating power requirements are within available limits. Capacitor trip devices can also be provided to operate the solenoid.

(2) Current operated solenoids supplied with current from bushing type or separate current transformers are available on the smaller circuit breakers, and like the capacitor trip devices, they are very useful in isolated areas where a separate operating power supply cannot be justified.

(3) All other types of operating mechanisms (except manual) described below use small control solenoids of ac or dc operation to initiate the major closing operation performed by the pneumatic, hydraulic or spring mechanisms.

b. Motor Operating Mechanisms

Motor operation of circuit breakers, like solenoids, were used mostly in the past on small circuit breakers and are still available from some suppliers. The motors can be ac or dc, usually of a high torque and high speed type to drive a spring loaded toggle over dead center and release to provide good closing speed.

c. Pneumohydraulic

Pneumohydraulic is a coined name for a combination of pneumatic and hydraulic operating mechanism. An air compressor provides high pressure air (up to several thousand psi) to a cylinder with a piston used to drive hydraulic fluid into a piping system and servo-mechanism to provide closing and tripping operations when the appropriate control signals are applied.

The pneumohydraulic system is an energy storage system, integral with the circuit breaker, and is required to be of sufficient size to permit at least five complete closing-opening operations at rated short-circuit current, starting at normal working pressure and without replenishment of the compressed air energy store. It provides very high speed closing and tripping.

This type of mechanism is normally available, from certain suppliers, on 121 kV and higher rated circuit breakers.

d. Pneumatic

Pneumatic operating mechanisms utilize compressed high pressure air (or other gas) to apply closing and tripping forces directly to the mechanism. A variation of pneumatic operation is pneumatic closing with a tripping spring being compressed during the pneumatic closing operation. The pressure varies widely among suppliers from a few hundred to several thousand psi.

Where the pneumatic energy storage is integral with the circuit breaker, it must be of sufficient size to permit at least two complete closing-opening operations at rated short-circuit current starting at normal working pressure and without replenishing the compressed air energy store.

Where the pneumatic energy storage is separate from the circuit breaker, it can be designed to any desired size for any desired combination of operations within the rating structure of the circuit breaker. It can also be utilized to operate (closing and tripping) several circuit breakers in a similar manner. It has almost unlimited flexibility for maintenance and emergency piping, valving, back-up compressors, nitrogen bottles, temporary high-pressure hosing, etc.

This type of mechanism is available on most circuit breakers rated 23 kV and higher of the bulk oil, air blast and closed-cycle gas blast types.

e. Motor-Charged Spring

Motor-charged spring operating mechanisms utilize a motor to compress a coil spring that holds this stored energy until a closing signal is received. Then the spring expands to close the circuit breaker and simultaneously to charge or compress a smaller coil spring, which is used to trip the circuit breaker. This trip spring may or may not be concentric with the closing spring, depending upon the individual design. The energy storage capability of a motor-compressed spring operating mechanism must be sufficient for an opening-closing-opening operation at rated short-circuit current, after which the spring compressing motor must not require more than ten seconds to compress the closing spring. Longer times are permissible through agreement between the purchaser and the manufacturer. In cases where the desired reclosing scheme depends on motor operation, a dc motor may be specified and supplied from a battery or rectifier.

The above described breaker mechanism provides high speed closing and tripping. This type of mechanism is available on 2.4 through 72.5 kV circuit breakers.

f. Manual-Charged Spring

Manual-charged spring operating mechanisms have very limited application. They are available only from a few suppliers. Applications where reclosing operation is not required would be suitable for this type of operating mechanism. Compression of the spring to store the closing energy is accomplished by a hand jack that may be portable or integral with the operating mechanism. Energy storage required consists of only one closing and one tripping operation.

g. Manual Operating Mechanisms

Manual operating mechanisms are only available on small circuit breakers. They utilize a lever operated toggle mechanism that releases energy from a relatively small spring. They may or may not have tripping capability. If they cannot trip, a back-up protective device must be applied.

5. Tests

Tests performed on circuit breakers can generally be classified as:

- Design tests
- Production tests
- Tests after delivery
- Field tests
- Conformance tests

These tests are fully described in ANSI C37.09, "American Standard Test Procedure for ac High Voltage Circuit Breakers." While a detailed discussion of these tests is beyond the scope of this bulletin, here is a general outline of the tests involved.

a. Design Tests

Design tests consist of the following types of tests:

(1) Continuous Current Carrying Tests

(2) Short-Circuit Tests

  (a) Symmetrical interrupting capability (polyphase and line-to-line)

  (b) Assymetrical interrupting capability (polyphase and line-to-line)

  (c) Interrupting capability for single line to ground fault

  (d) Closing, latching, carrying and interrupting capability

  (e) Short time current carrying capability

  (f) Reclosing capability

  (g) Standard Operating duty

  (h) Tripping delay

  (i) Interrupting time

  (j) Reclosing time

(3) Dielectric Strength Tests

  (a) Low frequency withstand, dry and wet

  (b) Full wave impulse withstand

  (c) Chopped wave impulse withstand

  (d) Impulse voltage test for interrupters and resistors

(4) Load Current Switching Capability

  (a) Shunt reactor switching

  (b) Capacitor switching

  (c) Line charging current switching

(5) Mechanical Life

b. Production Tests

Production tests are normally made by the manufacturer at the factory as part of the process of producing the circuit breaker. If the breaker is completely assembled prior to shipment, some of the production tests are made after final assembly, but other tests can often be made more effectively on components and subassemblies during or after manufacture.

If the circuit breaker is not completely assembled at the factory prior to shipment, appropriate tests on component parts should be made to check the quality of workmanship and uniformity of material used and to assure satisfactory performance when properly assembled at its destination. This performance may be verified by making tests after delivery.

Production tests and checks include the following:

(1) Current and linear coupler transformer tests

(2) Bushing tests

(3) Gas container tests (ASME certification)

(4) Pressure tests

(5) Nameplate check

(6) Leakage tests

(7) Resistor, heater, and coil check tests

(8) Control and secondary wiring check tests

(9) Clearance and mechanical adjustment check tests

(10) Mechanical operation tests

(11) Timing tests

(12) Stored energy system tests

(13) Conductivity of current path test

(14) Low-frequency withstand voltage tests on major insulation components

(15) Low-frequency withstand voltage tests on control and secondary wiring

c. Tests After Delivery

Tests made by the purchaser after delivery of the circuit breaker to supplement inspection in determining whether the breaker has arrived in good condition may consist of timing tests on closing, opening, and close-open, no-load operations and low-frequency voltage withstand tests at 75 percent of the rated low-frequency withstand voltage. Polarity and ratio tests on the current transformers are also recommended.

d. Field Tests

Field tests are made on operating systems usually to investigate the performance of circuit breakers under conditions that cannot be duplicated in the factory. They usually supplement factory tests and, therefore, may not provide a complete investigation of the breakers' capabilities. Emphasis is usually placed upon performance under the particular conditions for which the tests are made rather than upon a broad investigation, and the schedule and instrumentation are adapted accordingly.

Field tests may include transient recovery voltage performance, closing together two energized parts of a system operating at different levels of voltage and power factor, switching of full sized shunt reactors or capacitor banks, contact timing for mechanically linked breaker poles or air supply linked poles where air lines may differ in length, measurement of resistances and voltage sharing or division of opening and pre-insertion resistors, etc.

e. Conformance Tests

Conformance tests are those tests specifically made to demonstrate the conformance of a circuit breaker with ANSI standards.

6. Control and Auxiliary Power Requirements

Rated control voltages for power circuit breakers per existing standard ANSI C37.8 are shown in Table V-3 (see C37.8 for full particulars):

TABLE V-3

CONTROL POWER VOLTAGES FOR CIRCUIT BREAKERS

DIRECT CURRENT

		Power Supply		
Rated Voltage	Control	Solenoid or Motor Operator	Stored Energy Operator	Tripping Voltage Range
24	-	-	-	14-30
48	-	-	-	28-60
125	90-130	90-130	90-130	70-140
250	180-260	180-260	180-260	140-280

ALTERNATING CURRENT

		Power Supply		
Rated Voltage	Control	Solenoid or Motor Operator	Stored Energy Operator	Tripping Voltage Range
115	95-125	-	95-125	95-125
230	190-250	190-250	190-250	190-250

In addition to the above, it will be necessary to provide auxiliary power at the breaker for use in conjunction with heater elements, compressor motors, compartment lights, etc. Auxiliary power supplies are generally available in one of the forms shown in Table V-4.

TABLE V-4

TYPICAL AUXILIARY VOLTAGES USED WITH CIRCUIT BREAKERS

60 Hz Auxiliary Power	
Single Phase	Three Phase
115 V	115
230 V	230
	480/277

7. Purchase Evaluation

When evaluating different types of breaker construction for a specific substation, it is important to include the cost of necessary auxiliary equipment such as maintenance jacks, gas handling equipment, oil handling equipment, tank lifters, etc. Environmental considerations of esthetics, noise and oil spills may also affect the choice of breaker type.

8. Shipment and Installation

a. Shipment

Immediately upon receipt, breakers should be examined for any damage en route. If injury is evident or indication of rough handling is visible, the carrier (transportation company) and the manufacturer should be notified promptly.

Method of shipment will be dictated by many things including size of breaker, destination, urgency of delivery, etc. In general, the small to medium (138 - 230 kV) size oil breakers will be shipped fully assembled. Although rail shipment is common, some deliveries are made by truck.

b. Assembly and Installation

Detailed discussion of assembly and installation of circuit breakers is beyond the scope of this bulletin. However, additional comments can be found in NEMA publication SG4, Part 6 "Instructions for the Installation, Operation and Care of Alternating-Current High-Voltage Circuit Breakers."

REFERENCES

1. IEEE Tutorial Course Text No. 75CH0975-3-PWR.

2. Loading of Substation Electrical Equipment with Emphasis on Thermal Capability, IEEE 1977 Summer Power Meeting

   Part I - Principles by B. J. Conway, D. W. McMullen, A. J. Peat and J. M. Scofield of Southern California Edison Company.

   Part II - Application by I. S. Benko, D. E. Cooper, D. O. Craghead and P. Q. Nelson of Southern California Edison Company.

APPENDIX

TO

POWER CIRCUIT BREAKERS

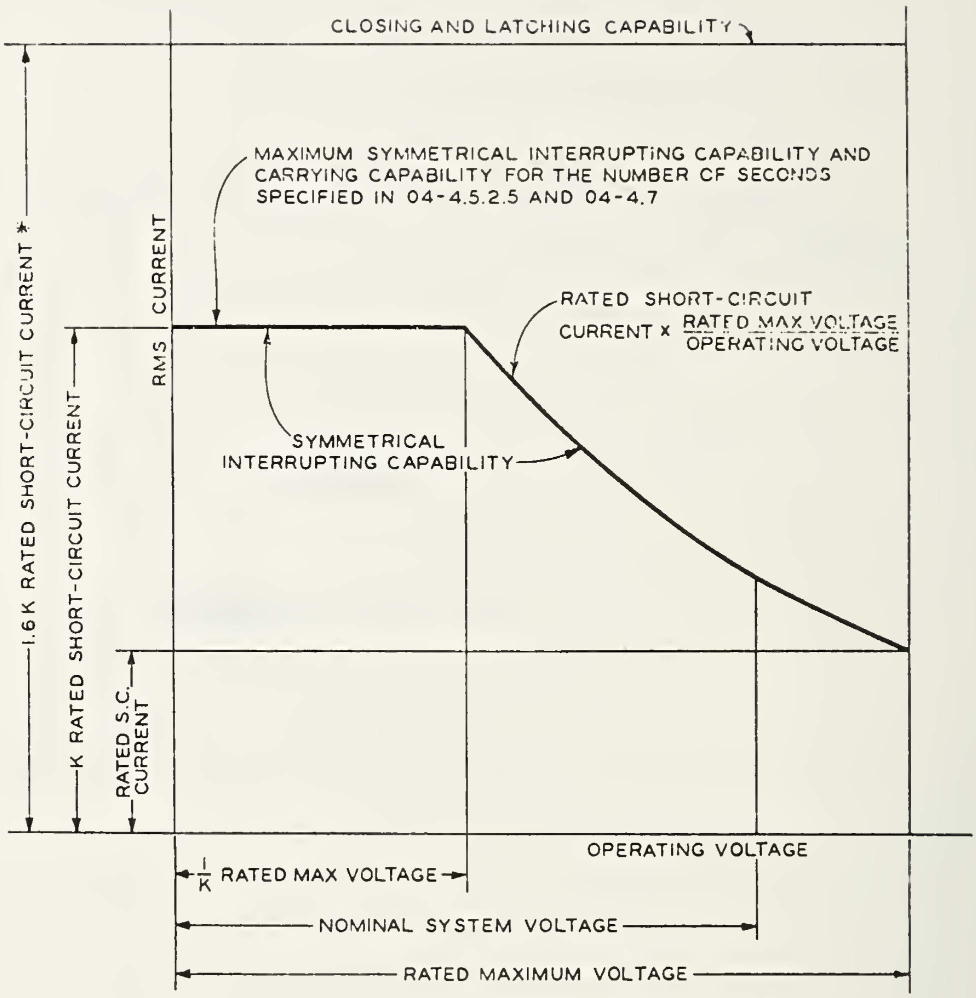

Fig. 1

Relation of Symmetrical Interrupting Capability, Closing Capability, Latching Capability, and Carrying Capability to Rated Short-Circuit Current

* Or 2.7K times rated short-circuit current if current is measured in peak amperes.

NOTE: K equals voltage range factor. (For preferred standard values, see American Standard C37.06-1964.)

Ref. C37.04

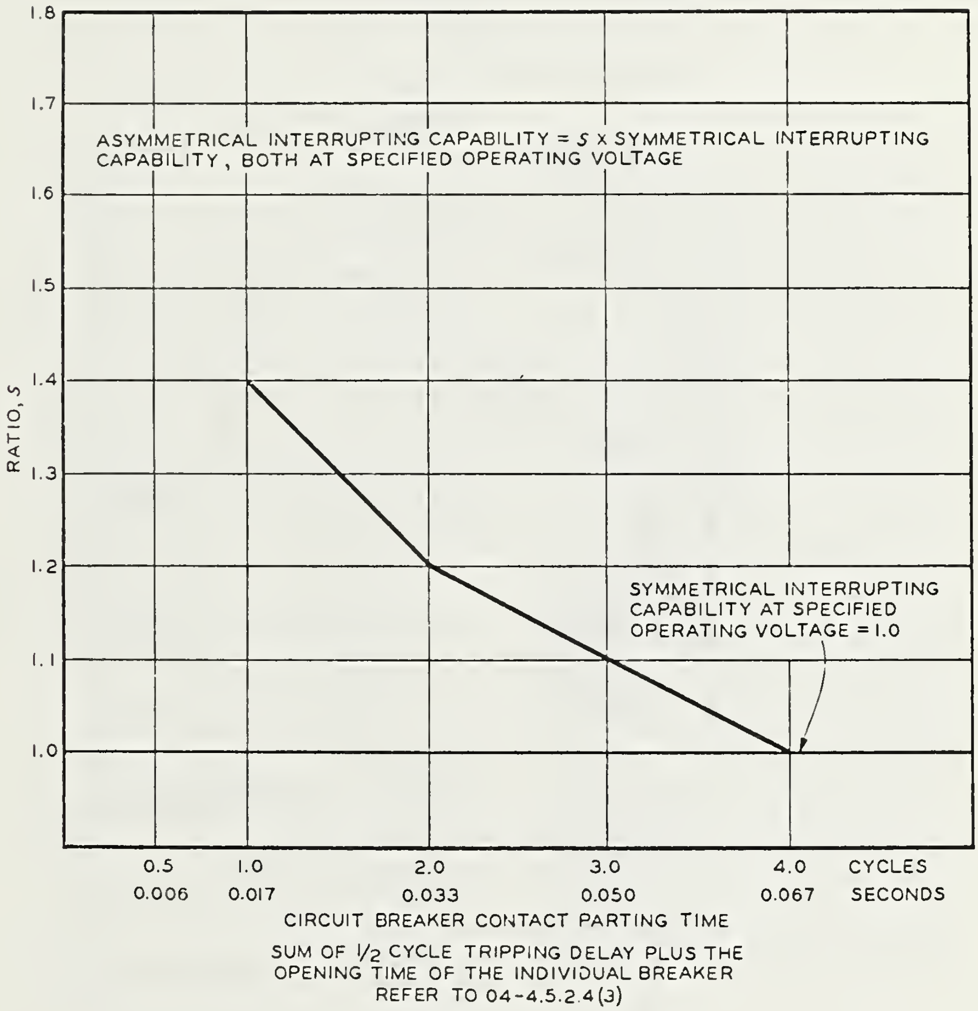

Fig. 2

Ratio of Circuit Breaker Asymmetrical to Symmetrical Interrupting Capabilities

NOTE: For relation of symmetrical interrupting capability at specified operating voltage to rated short-circuit current, see Fig. 1.

Ref. C37.04

Table 1
Schedule of Preferred Ratings for Indoor Oil Circuit Breakers
(Symmetrical Current Basis of Rating)

	Identification		Rated Values									Related Required Capabilities			
			Voltage		Insulation Level		Current					Current Values		
					Rated Withstand Test Voltage									
Line No	Nominal Voltage Class (1)* kV, rms	Nominal 3 Phase MVA Class (1)	Rated Max Voltage (2) kV, rms	Rated Voltage Range Factor, K (3)	Low Frequency kV, rms	Impulse (4) kV, Crest	Rated Continuous Current at 60 Hz (5) Amperes, rms	Rated Short-Circuit Current (at Rated Max kV) (6) (7) (12) kA rms	Rated Interrupting Time (8) Cycles	Rated Permissible Tripping Delay, Y (12) Seconds	Rated Max Voltage Divided by K kV, rms	Max Symmetrical Interrupting Capability (9) (12) — K Times Rated Short-Circuit Current kA, rms	3 Second Short Time Current Carrying Capability (10) — K Times Rated Short-Circuit Current kA, rms	Closing and Latching Capability 1.6 K Times Rated Short Circuit Current (10) (11) (12) kA, rms
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14
1	4.16	50	4.76	2.07	19	60	1200	6.1	8	See	2.3	13	13	See
2	7.2	50	8.25	3.59	26	75	600	3.5	8		2.3	13	13	
3	7.2	100	8.25	3.59	26	75	600	7.0	8	Note	2.3	25	25	Note
4	7.2	100	8.25	3.59	26	75	1200	7.0	8		2.3	25	25	
5	7.2	100	8.25	3.59	26	75	2000	7.0	8		2.3	25	25	
6	13.8	150	15.0	3.75	36	95	600	5.8	8		4.0	22	22	
7	13.8	150	15.0	3.75	36	95	1200	5.8	8	12	4.0	22	22	12
8	13.8	250	15.0	3.75	36	95	1200	9.8	8		4.0	37	37	
9	13.8	500	15.0	2.27	36	95	1200	19	8		6.6	43	43	
10	13.8	500	15.0	2.27	36	95	2000	19	8		6.6	43	43	

Ref. C37.06

Notes to Table 1:

* Numbers in parentheses refer to the notes below.

NOTES:

These ratings were prepared by the EEI-AEIC-NEMA Joint Committee on Power Circuit Breakers.

For service conditions, definitions, and interpretation of ratings, tests, and qualifying terms, see American National Standards C37.03-1964, C37.04-1964, C37.04a-1964, C37.04b-1970, C37.09-1964, and C37.09a-1970.

The interrupting ratings are for 60 Hz systems. Applications on 25 Hz systems should receive special consideration.

Current values have been rounded off to the nearest kiloampere (kA) except below 10 kA where two significant figures are used.

(1) For reference only. Figures in Col 2 must not be used for evaluation of breaker in any specific application. Actual application must be based on rated short-circuit current at rated maximum voltage and in accordance with Notes 6 and 7.

(2) The voltage rating is based on American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz), C84.1-1970, where applicable, and is the maximum voltage for which the breaker is designed and the upper limit for operation.

(3) The rated voltage range factor, K, is the ratio of rated maximum voltage to the lower limit of the range of operating voltage in which the required symmetrical and asymmetrical current interrupting capabilities vary in inverse proportion to the operating voltage.

(4) 1.2 x 50 microsecond positive and negative wave. All impulse values are phase-to-phase and phase-to-ground and across the open contacts.

(5) The 25 Hz continuous current ratings in amperes are given herewith following the respective 60 Hz rating: 600-700; 1200-1400; 2000-2250.

(6) To obtain the required symmetrical current interrupting capability of a circuit breaker at an operating voltage between $1/K$ times rated maximum voltage and rated maximum voltage, the following formula shall be used:

Required Symmetrical Current Interrupting Capability =

$$\text{Rated Short-Circuit Current}\left(\frac{\text{Rated Maximum Voltage}}{\text{Operating Voltage}}\right)$$

For operating voltages below $1/K$ times rated maximum voltage, the required symmetrical current interrupting capability of the circuit breaker shall be equal to K times rated short-circuit current.

(7) With the limitation stated in 04-4.5 of American National Standard C37.04-1964, all values apply for polyphase and line-to-line faults. For single phase-to-ground faults, the specific conditions stated in 04-4.5.2.3 of American National Standard C37.04-1964 apply.

(8) The ratings in this column are on a 60 Hz basis and are the maximum time interval to be expected during a breaker opening operation between the instant of energizing the trip circuit and interruption of the main circuit on the primary arcing contacts under certain specified conditions. The values may be exceeded under certain conditions as specified in 04-4.8 of American National Standard C37.04-1964.

(9) Current values in this column are not to be exceeded even for operating voltages below $1/K$ times rated maximum voltage. For voltages between rated maximum voltage and $1/K$ times rated maximum voltage, follow (6) above.

(10) Current values in this column are independent of operating voltage up to and including rated maximum voltage.

(11) If currents are to be expressed in peak amperes, multiply values in this column by a factor of 1.69 which is a ratio of 2.7/1.6.

(12) For lines 1 through 10, the breakers were designed under earlier standards and are not required to be retested in accordance with American National Standard C37.09-1964 because decreasing usage discourages the necessary designing and testing to meet these standards. They will not close and latch against $1.6K$ times rated short-circuit current as required in 04-4.5 of American National Standard C37.04-1964. Therefore, when these breakers are applied to systems which have symmetrical short-circuit current (60 percent of Col 12), they must be applied to open with no intentional time delay. If the symmetrical short-circuit current equals 60 percent of K times rated short-circuit current, the latching ability is adequate and a permissible tripping delay of up to two seconds may be used. The permissible tripping delay increases for lesser currents directly as the square of the ratio of 60 percent of the current in Col 12 to the actual symmetrical current through the breaker. In the normally closed position, the breakers will successfully pass the inrush currents up to 1.6 times the values listed in Col 12 and carry the associated decaying currents for two seconds before interrupting the maximum values stated in Col 12.

Ref. C37.06

Table 2
Schedule of Preferred Ratings for Indoor Oilless Circuit Breakers
(Symmetrical Current Basis of Rating)

	Identification		Rated Values								Related Required Capabilities			
			Voltage		Insulation Level		Current					Current Values		
					Rated Withstand Test Voltage							Max Symmetrical Interrupting Capability (9)	3 Second Short Time Current Carrying Capability (10)	Closing and Latching Capability 1.6 K Times Rated Short Circuit Current (10) (11)
												K Times Rated Short Circuit Current		
Line No.	Nominal Voltage Class (1)* kV, rms	Nominal 3 Phase MVA Class (1)	Rated Max Voltage (2) kV, rms	Rated Voltage Range Factor, K (3)	Low Frequency kV, rms	Impulse (4) kV, Crest	Rated Continuous Current at 60 Hz (5) Amperes, rms	Rated Short-Circuit Current (at Rated Max kV) (6) (7) kA, rms	Rated Interrupting Time (8) Cycles	Rated Permissible Tripping Delay, Y Seconds	Rated Max Voltage Divided by K kV, rms	kA, rms	kA, rms	kA, rms
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14
1	4.16	75	4.76	1.36	19	60	1200	8.8	5	2	3.5	12	12	19
2	4.16	150	4.76	1.36	19	60	1200	18	5	2	3.5	24	24	39
3	4.16	250	4.76	1.24	19	60	1200	29	5	2	3.85	36	36	58
4	4.16	250	4.76	1.24	19	60	2000	29	5	2	3.85	36	36	58
5	4.16	350	4.76	1.19	19	60	1200	41	5	2	4.0	49	49	78
6	4.16	350	4.76	1.19	19	60	3000	41	5	2	4.0	49	49	78
7	7.2	250	8.25	1.79	36	95	1200	17	5	2	4.6	30	30	49
8	7.2	500	8.25	1.25	36	95	1200	33	5	2	6.6	41	41	66
9	7.2	500	8.25	1.25	36	95	2000	33	5	2	6.6	41	41	66
10	13.8	250	15	2.27	36	95	1200	9.3	5	2	6.6	21	21	34
11	13.8	500	15	1.30	36	95	1200	18	5	2	11.5	23	23	37
12	13.8	500	15	1.30	36	95	2000	18	5	2	11.5	23	23	37
13	13.8	750	15	1.30	36	95	1200	28	5	2	11.5	36	36	58
14	13.8	750	15	1.30	36	95	2000	28	5	2	11.5	36	36	58
15	13.8	1000	15	1.30	36	95	1200	37	5	2	11.5	48	48	77
16	13.8	1000	15	1.30	36	95	3000	37	5	2	11.5	48	48	77

Ref. C37.06

Notes to Table 2:

* Numbers in parentheses refer to the notes below.

NOTES:

These ratings were prepared by the EEI-AEIC-NEMA Joint Committee on Power Circuit Breakers.

For service conditions, definitions, and interpretation of ratings, tests, and qualifying terms, see American National Standards C37.03-1964, C37.04-1964, C37.04a-1964, C37.04b-1970, C37.09-1964 and C37.09a-1970.

The interrupting ratings are for 60 Hz systems. Applications on 25 Hz systems should receive special consideration.

Current values have been rounded off to the nearest kiloampere except below 10 kA where two significant figures are used.

(1) For reference only. Figures in Col 2 must not be used for evaluation of circuit breaker in any specific application. Actual application must be based on rated short-circuit current at rated maximum voltage and in accordance with Notes 6 and 7.

(2) The voltage rating is based on American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz), C84.1-1970, where applicable and is the maximum voltage for which the circuit breaker is designed and the upper limit for operation.

(3) The rated voltage range factor, K, is the ratio of rated maximum voltage to the lower limit of the range of operating voltage in which the required symmetrical and asymmetrical current interrupting capabilities vary in inverse proportion to the operating voltage.

(4) 1.2 x 50 microsecond positive and negative wave. All impulse values are phase-to-phase and phase-to-ground and across the open contacts.

(5) The 25 Hz continuous current ratings in amperes are given herewith following the respective 60 Hz rating: 1200-1400; 2000-2250; 3000-3500.

(6) To obtain the required symmetrical current interrupting capability of a circuit breaker at an operating voltage between $1/K$ times rated maximum voltage and rated maximum voltage, the following formula shall be used:

Required Symmetrical Current Interrupting Capability =

$$\text{Rated Short-Circuit Current} \left(\frac{\text{Rated Maximum Voltage}}{\text{Operating Voltage}}\right)$$

For operating voltages below $1/K$ times rated maximum voltage, the required symmetrical current interrupting capability of the circuit breaker shall be equal to K times rated short-circuit current.

(7) With the limitation stated in 04-4.5 of American National Standard C37.04-1964, all values apply for polyphase and line-to-line faults. For single phase-to-ground faults, the specific conditions stated in 04-4.5.2.3 of American National Standard C37.04-1964 apply.

(8) The ratings in this column are on a 60 Hz basis and are the maximum time interval to be expected during a breaker opening operation between the instant of energizing the trip circuit and interruption of the main circuit on the primary arcing contacts under certain specified conditions. The values may be exceeded under certain conditions as specified in 04-4.8 of American National Standard C37.04-1964.

(9) Current values in this column are not to be exceeded even for operating voltages below $1/K$ times rated maximum voltage. For voltages between rated maximum voltage and $1/K$ times rated maximum voltage, follow (6) above.

(10) Current values in this column are independent of operating voltage up to and including rated maximum voltage.

(11) If currents are to be expressed in peak amperes, multiply values in this column by a factor of 1.69 which is a ratio of 2.7/1.6

Ref. C37.06

Table 3
Schedule of Preferred Ratings for Outdoor Oil Circuit Breakers
(Symmetrical Current Basis of Rating)

	Identification		Rated Values									Related Required Capabilities			
			Voltage		Insulation Level		Current					Current Values		
					Rated Withstand Test Voltage (4)									
Line No.	Nominal Voltage Class (1)* kV, rms	Nominal 3 Phase MVA Class (1)	Rated Max Voltage (2) kV, rms	Rated Voltage Range Factor, K (3)	Low Frequency kV, rms	Impulse kV, Crest	Rated Continuous Current at 60 Hz (5) Amperes, rms	Rated Short-Circuit Current (at Rated Max kV) (6) (7) kA, rms	Rated Interrupting Time (8) Cycles	Rated Permissible Tripping Delay, Y Seconds	Rated Max Voltage Divided by K kV rms	Max Symmetrical Interrupting Capability (9) — K Times Rated Short Circuit Current kA rms	3 Second Short Time Current Carrying Capability (10) — K Times Rated Short Circuit Current kA rms	Closing and Latching Capability 1.6 K Times Rated Short Circuit Current (10) (11)
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14
1	14.4	250	15.5	2.67	See	See	600	8.9	5	2	5.8	24	24	38
2	14.4	500	15.5	1.29			1200	18	5	2	12	23	23	37
3	23	500	25.8	2.15	Note	Note	1200	11	5	2	12	24	24	38
4	34.5	1500	38	1.65			1200	22	5	2	23	36	36	58
5	46	1500	48.3	1.21	4	4	1200	17	5	2	40	21	21	33
6	69	2500	72.5	1.21			1200	19	5	2	60	23	23	37

Ref. C37.06

Notes to Table 3:

*Numbers in parentheses refer to the notes below.

NOTES:

These ratings were prepared by the EEI-AEIC-NEMA Joint Committee on Power Circuit Breakers.

For service conditions, definitions, and interpretation of ratings, tests, and qualifying terms, see American National Standards C37.03-1964, C37.04-1964, C37.04a-1964, C37.04b-1970, C37.09-1964 and C37.09a-1970.

The interrupting ratings are for 60 Hz systems. Applications on 25 Hz systems should receive special consideration.

Current values have been rounded off to the nearest kiloampere except below 10 kA, where two significant figures are used.

(1) For reference only. Figures in Col 2 must not be used for evaluation of circuit breaker in any specific application. Actual application must be based on rated short-circuit current at rated maximum voltage and in accordance with Notes 6 and 7.

(2) The voltage rating is based on American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz), C84.1-1970, where applicable and is the maximum voltage for which the circuit breaker is designed and the upper limit for operation.

(3) The rated voltage range factor, K, is the ratio of rated maximum voltage to the lower limit of the range of operating voltage in which the required symmetrical and asymmetrical current interrupting capabilities vary in inverse proportion to the operating voltage.

(4) For dielectric test values, refer to Table 5 of this standard.

(5) The 25 Hz continuous current ratings in amperes are given herewith following the respective 60 Hz ratings: 600-700; 1200-1400

(6) To obtain the required symmetrical current interrupting capability of a circuit breaker at an operating voltage between $1/K$ times rated maximum voltage and rated maximum voltage, the following formula shall be used:

Required Symmetrical Current Interrupting Capability

$$\text{Rated Short-Circuit Current}\left(\frac{\text{Rated Maximum Voltage}}{\text{Operating Voltage}}\right)$$

For operating voltages below $1/K$ times rated maximum voltage, the required symmetrical current interrupting capability of the circuit breaker shall be equal to K times rated short-circuit current.

(7) With the limitation stated in 04-4.5 of American National Standard C37.04-1964, all values apply for polyphase and line-to-line faults. For single phase-to-ground faults the specific conditions stated in 04-4.5.2.3 of American National Standard C37.04-1964 apply.

(8) The ratings in this column are on a 60 Hz basis and are the maximum time interval to be expected during a breaker opening operation between the instant of energizing the trip circuit and interruption of the main circuit on the primary arcing contacts under certain specific conditions. The values may be exceeded under certain conditions as specified in 04-4.8 of American National Standard C37.04-1964.

(9) Current values in this column are not to be exceeded even for operating voltages below $1/K$ times rated maximum voltage. For voltages between rated maximum voltage and $1/K$ times rated maximum voltage, follow (6) above.

(10) Current values in this column are independent of operating voltage up to and including rated maximum voltage.

(11) If currents are to be expressed in peak amperes, multiply values in this column by a factor of 1.69 which is a ratio of 2.7/1.6.

Table 4
Schedule of Preferred Ratings for Outdoor Oilless Circuit Breakers
(Symmetrical Current Basis of Rating)

Line No.	Identification		Rated Values									Related Required Capabilities			
			Voltage		Insulation Level: Rated Withstand Test Voltage (4)		Current					Current Values		
	Nominal Voltage Class (1)* kV, rms	Nominal 3 Phase MVA Class (1)	Rated Max Voltage (2) kV, rms	Rated Voltage Range Factor, K (3)	Low Frequency kV, rms	Impulse kV, Crest	Rated Continuous Current at 60 Hz (5) Amperes, rms	Rated Short-Circuit Current (at Rated Max kV) (6) (7) kA, rms	Rated Interrupting Time (8) Cycles	Rated Permissible Tripping Delay, Y Seconds	Rated Max Voltage Divided by K kV, rms	Max Symmetrical Interrupting Capability (9) — K Times Rated Short Circuit Current kA, rms	3 Second Short-Time Current Carrying Capability (10) — K Times Rated Short Circuit Current kA, rms	Closing and Latching Capability 1.6 K Times Rated Short Circuit Current (10) (11) kA, rms
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14
1	34.5	1500	38	1.65	See Note 4	See Note 4	1200	22	5	2	23	36	36	58
2	69	5000	72.5	1.10	See Note 4	See Note 4	2000	37	3	2	66	41	41	65

Ref. C37.06

Notes to Table 4:

* Numbers in parentheses refer to the notes below.

NOTES:

These ratings were prepared by the EEI-AEIC-NEMA Joint Committee on Power Circuit Breakers.

For service conditions, definitions, and interpretation of ratings, tests, and qualifying terms, see American National Standards C37.03-1964, C37.01-1964, C37.04a-1964, C37.04b-1970, C37.09-1964 and C37.09a-1970.

The interrupting ratings are for 60 Hz systems. Applications on 25 Hz systems should receive special consideration.

Current values have been rounded off to the nearest kiloampere, except below 10 kA where two significant figures are used.

(1) For reference only. Figures in Col 2 must not be used for evaluation of circuit breaker in any specific application. Actual application must be based on rated short-circuit current at rated maximum voltage and in accordance with Notes 6 and 7.

(2) The voltage rating is based on American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz), C84.1-1970, where applicable, and is the maximum voltage for which the circuit breaker is designed and the upper limit for operation.

(3) The rated voltage range factor, K, is the ratio of rated maximum voltage to the lower limit of the range of operating voltage in which the required symmetrical and asymmetrical current interrupting capobilities vary in inverse proportion to the operating voltage.

(4) For dielectric test values, refer to Table 5 of this standard.

(5) The 25 Hz continuous current ratings in amperes are given herewith following the respective 60 Hz ratings: 1200-1400; 2000-2250.

(6) To obtain the required symmetrical current interrupting capability of a circuit breaker at an operating voltage between $1/K$ times rated maximum voltage and rated maximum voltage, the following formula shall be used:

$$\text{Required Symmetrical Current Interrupting Capobility} = \text{Rated Short-Circuit Current}\left(\frac{\text{Rated Maximum Voltage}}{\text{Operating Voltage}}\right)$$

For operating voltages below $1/K$ times rated maximum voltage, the required symmetrical current interrupting capability of the circuit breaker shall be equal to K times rated short-circuit current.

(7) With the limitation stated in 04-4.5 of American National Standard C37.04-1964, all values apply for polyphase and line-to-line faults. For single phase-to-ground faults, the specific conditions stated in 04-4.5.2.3 of American National Standard C37.04-1964 apply.

(8) The ratings in this column are on a 60 Hz basis and are the maximum time interval to be expected during a breaker opening operation between the instant of energizing the trip circuit and interruption of the main circuit on the primary arcing contacts under certain specific conditions. The values may be exceeded under certain conditions as specified in 04-4.8 of American National Standard C37.04-1964.

(9) Current values in this column are not to be exceeded even for operating voltages below $1/K$ times rated maximum voltage. For voltages between rated maximum voltoge and $1/K$ times rated maximum voltage, follow (6) above.

(10) Current values in this column are independent of operating voltage up to and including rated maximum voltage.

(11) If currents are to be expressed in peak amperes, multiply values in this column by a factor of 1.69 which is a ratio of 2.7/1.6.

Ref. C37.06

Table 4A

Schedule of Preferred Ratings for Outdoor Circuit Breakers (Symmetrical Current Basis of Rating)

Line No.	Identification: Nominal Voltage Class (1)* kV, rms	Identification: Nominal 3 Phase MVA Class	Rated Values – Voltage: Rated Max Voltage (2) kV, rms	Rated Values – Voltage: Rated Voltage Range Factor, K (3)	Rated Values – Insulation Level, Rated Withstand Test Voltage (4): Low Frequency kV, rms	Rated Values – Insulation Level, Rated Withstand Test Voltage (4): Impulse kV, Crest	Rated Values – Current: Rated Continuous Current at 60 Hz (5) Amperes, rms	Rated Values – Current: Rated Short-Circuit Current (at Rated Max kV) (6) kA, rms	Rated Values: Rated Interrupting Time (7) Cycles	Rated Values: Rated Permissible Tripping Delay, Y Seconds	Related Required Capabilities: Rated Max Voltage Divided by K kV, rms	Related Required Capabilities – Current Values: Max Symmetrical Interrupting Capability (8) – K Times Rated Short Circuit Current kA, rms	Related Required Capabilities – Current Values: 3 Second Short Time Current Carrying Capability (9) – K Times Rated Short Circuit Current kA, rms	Related Required Capabilities – Current Values: Closing and Latching Capability 1.6 K Times Rated Short-Circuit Current (9) (10) kA, rms
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14
1	115		121	1.0			1200	20	3	1	121	20	20	32
2	115		121	1.0			1600	40	3	1	121	40	40	64
3	115		121	1.0			2000	40	3	1	121	40	40	64
4	115		121	1.0			2000	63	3	1	121	63	63	101
5	115		121	1.0	See	See	3000	40	3	1	121	40	40	64
6	115		121	1.0			3000	63	3	1	121	63	63	101
7	138		145	1.0			1200	20	3	1	145	20	20	32
8	138	Not	145	1.0	Note	Note	1600	40	3	1	145	40	40	64
9	138		145	1.0			2000	40	3	1	145	40	40	64
10	138		145	1.0	4	4	2000	63	3	1	145	63	63	101
11	138		145	1.0			2000	80	3	1	145	80	80	128
12	138	Applica-	145	1.0			3000	40	3	1	145	40	40	64
13	138		145	1.0			3000	63	3	1	145	63	63	101
14	138		145	1.0			3000	80	3	1	145	80	80	128
15	161	ble	169	1.0			1200	16	3	1	169	16	16	26
16	161		169	1.0			1600	31.5	3	1	169	31.5	31.5	50
17	161		169	1.0			2000	40	3	1	169	40	40	64
18	161		169	1.0			2000	50	3	1	169	50	50	80
19	230(11)		242(11)	1.0			1600	31.5	3	1	242	31.5	31.5	50
20	230(11)		242(11)	1.0			2000	31.5	3	1	242	31.5	31.5	50
21	230(11)		242(11)	1.0			3000	31.5	3	1	242	31.5	31.5	50
22	230(11)		242(11)	1.0			2000	40	3	1	242	40	40	64
23	230(11)		242(11)	1.0			3000	40	3	1	242	40	40	64
24	230(11)		242(11)	1.0			3000	63	3	1	242	63	63	101
25	345(11)		362(11)	1.0			2000	40	3	1	362	40	40	64
26	345(11)		362(11)	1.0			3000	40	3	1	362	40	40	64
27	500(11)		550(11)	1.0			2000	40	2	1	550	40	40	64
28	500(11)		550(11)	1.0			3000	40	2	1	550	40	40	64
29	700(11)		765(11)	1.0			2000	40	2	1	765	40	40	64
30	700(11)		765(11)	1.0			3000	40	2	1	765	40	40	64

Ref. C37.06

Notes to Table 4A:

*Numbers in parentheses refer to the notes below.

NOTES:

These ratings were prepared by the EEI-AEIC-NEMA Joint Committee on Power Circuit Breakers.

For service conditions, definitions, and interpretation of ratings, tests, and qualifying terms, see American National Standards C37.03-1964, C37.04-1964, C37.04a-1964, C37.04b-1970, C37.09-1964, and C37.09a-1970.

The interrupting ratings are for 60 Hz systems. Applications on 25 Hz systems should receive special consideration.

(1) For reference only.

(2) The voltage rating is based on American National Standard Voltage Ratings for Electric Power Systems and Equipment (60 Hz), C84.1-1970, where applicable, and is the maximum voltage for which the circuit breaker is designed and the upper limit for operation.

(3) The rated voltage range factor, K, is the ratio of rated maximum voltage to the lower limit of the range of operating voltage in which the required symmetrical and asymmetrical current interrupting capabilities vary in inverse proportion to the operating voltage except for Table 4A where $K = 1.0$.

(4) For dielectric test values, refer to Table 5 of this standard.

(5) The 25 Hz continues current ratings in amperes are given herewith following the respective 60 Hz ratings: 1200-1400; 1600-1800; 2000-2250; 3000-3500.

(6) With the limitation stated in 04-4.5 of American National Standard C37.04-1964, all values apply for polyphase and line-to-line faults. For single phase-to-ground faults, the specific conditions stated in 04-4.5.2.3 of American National Standard C37.04-1964 apply.

(7) The ratings in this column are on a 60 Hz basis and are the maximum time interval to be expected during a breaker opening operation between the instant of energizing the trip circuit and interruption of the main circuit on the primary arcing contacts under certain specific conditions. The values may be exceeded under certain conditions as specified in 04-4.8 of American National Standard C37.04-1964.

(8) Current values in this column are not to be exceeded even for operating voltages below rated maximum voltage.

(9) Current values in this column are independent of operating voltages up to and including rated maximum voltage.

(10) If currents are to be expressed in peak amperes, multiply values in this column by a factor of 1.69 which is a ratio of 2.7/1.6.

(11) The circuit breakers listed in Lines 19 through 30 are intended for application only on systems effectively grounded, as defined in *Neutral Grounding Devices*, IEEE Publication No. 32, May 1947.

Table 5
Schedule of Dielectric Test Values for Outdoor AC High-Voltage Circuit Breakers*

Line No.	Rated Max Voltage kV, rms	Insulation Withstand Test Voltages: Low Frequency Withstand	Impulse Tests, 1.2 x 50 Microsecond Wave: Full Wave† Withstand kV, rms	Chopped Wave, kV, Crest† Min Time to Sparkover: 2 Microseconds Withstand	Chopped Wave, kV, Crest† Min Time to Sparkover: 3 Microseconds Withstand	Interrupter Full Wave kV, Crest
	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6
1	15.5	50	110	142	126	—
2	25.8	60	150	194	172	—
3	38.0	80	200	258	230	—
4	48.3	105	250	322	288	—
5	72.5	160	350	452	402	—
6	121.0	260	550	710	632	412
7	145	310	650	838	748	488
8	169	365	750	968	862	562
9	242‡	425	900	1160	1040	675
10	362‡	555	1300	1680	1500	975
11	550‡	860	1800	2320	2070	1350
12	765‡	960	2050	2640	2360	1540

* Refer to Tables 3, 4, and 4A of this standard.

† 1.2 x 50 microsecond positive and negative wave. All impulse values are phase-to-phase and phase-to-ground and across the open contacts.

‡ These circuit breakers are intended for application only on systems effectively grounded, as defined in *Neutral Grounding Devices*, IEEE Publication No. 32, May 1947.

NOTE: For dielectric test voltage values for indoor ac high-voltage circuit breakers, see Tables 1 and 2 of this standard.

Ref. C37.06

D. METAL-CLAD SWITCHGEAR

1. General

a. Scope

This section will deal primarily with metal-clad switchgear for use in distribution type substations. Metal-clad switchgear is defined as a type of metal-enclosed power switchgear with a number of necessary characteristics. These characteristics are fully defined in ANSI Standard C37.20, Section 20-2.1.3.1. Briefly, they are:

(1) The main switching or interrupting device is of the removable type.

(2) Major components of the primary circuit are enclosed and are separated by grounded metal barriers.

(3) All live parts are enclosed within grounded metal compartments with automatic shutters to block off energized parts when devices are disconnected.

(4) The primary bus is covered with insulating material throughout.

(5) There are mechanical interlocks for safety and proper operation.

(6) Secondary devices are essentially isolated from primary elements.

(7) A door to circuit interrupting device may serve as a control panel or for access to some secondary elements.

b. Function

Metal-clad switchgear serves the same system function as comparable elements in a conventional open bus type substation. These elements may include main power switching or interrupting devices, disconnecting switches, buses, instrument and control power transformers, control and auxiliary devices, as well as other devices.

Metal-clad switchgear is usually considered for special applications where appearance, compactness, frequent maintenance in foul weather, or safety is of paramount importance. It will generally cost more installed than its conventional equivalent. For this reason, few applications will be justified on REA Borrower's Systems.

c. Applicable National Standards

The main standards governing metal-clad switchgear are: ANSI C37.20 (IEEE-27), Switchgear Assemblies and Metal-Enclosed Bus; NEMA SG-5 on Switchgear Assemblies; and SG-6 on Switchgear Equipment. Additional standards applicable are listed in the references at the end of this section.

2. Types

Metal-clad switchgear is available for both indoor and outdoor installations. The basic switchgear is the same for both types of installations. For outdoor installations, a weatherproof enclosure is provided. Weatherproof enclosures are made in several arrangements such as: single cubicle line up, without an enclosed aisle; single line up, with enclosed aisle; double line up, with a common enclosed center aisle. Manufacturers have adopted tradenames for the various arrangements.

Any decision as to choice of indoor or outdoor type should include a cost analysis. A rough rule of thumb is that outdoor units in weatherproof enclosures will usually cost less than indoor units (plus the cost of a prefabricated or similar type building) if fewer than 10 sections are required. Other factors, of course, may influence the decision such as joint use of any building for other purposes.

Metal-clad switchgear sections or cubicles are made for every recognized type of switching scheme, including straight bus (radial circuits), network, sectionalized bus, main and transfer bus, breaker and half, ring bus, double bus-double breaker, etc. Sections are made or can be adapted for almost any conceivable arrangement of the equipment usually required in circuits for feeders, transformers, generators, synchronous or induction motors, reactors and capacitors. Entrance provisions can be adapted to accommodate overhead (through roof bushings)

circuits or underground through conduit circuits. Sections are made to accommodate all sorts of auxiliary equipment such as current and potential transformers, station power transformers, fuses, switches, surge arresters, battens, etc.

3. Ratings

a. Rated Nominal Voltage (rms)

Rated nominal voltage of a switchgear assembly is the value assigned for identification. Standard ratings are 4.16, 7.2 and 13.8 kV. See ANSI C37.20, Table I.

b. Rated Maximum Voltage (rms)

Rated maximum voltage is the highest rms voltage for which the equipment is designed and is the upper limit for operations. Standard ratings corresponding, respectively, to the values given in (a) preceding are 4.76, 8.25 and 15.0 kV. See ANSI C37.20, Table I.

c. Rated Frequency

Ratings for ac equipment are based on a frequency of 60 Hz.

d. Rated Insulation Levels

Rated insulation levels consist of two items: (1) 60 Hz, one minute withstand voltage and (2) impulse withstand voltage or BIL. The standard values are shown in the following table:

Rated Nominal Voltage (rms)	60 Hz, 1 Min Withstand	BIL
4.16 kV	19 kV	60 kV
7.2 kV	36 kV	95 kV
13.8 kV	36 kV	95 kV

e. Rated Continuous Current

This is the maximum current in rms amperes at rated frequency that can be carried continuously by the primary circuit components, including buses and

connections, without causing temperatures in excess of specified limits for any component. The standard ratings for the bus are 1200, 2000, and 3000 amperes. The continuous current ratings of the individual units shall correspond to the ratings of the switching and interrupting devices used.

f. Rated Short-Time or Momentary Current

This is the maximum rms total current that can be carried momentarily without electrical, thermal or mechanical damage. Standard ratings for bus are 20, 40, 60 and 80 kA for 4.16 kV rated and 20, 35, 40, 60 and 80 kA for 13.8 kV rated assemblies. Momentary ratings of the individual units shall correspond to the ratings of the devices used.

g. Interrupting or Switching Capability

Interrupting or switching capability of a particular device such as circuit breaker, interrupter switch, fuse, etc., used in a switchgear assembly is determined by the rated capabilities of that device as listed in the appropriate standards.

4. Purchase Considerations

a. Procurement

Metal-clad switchgear assemblies for a particular job are normally purchased as a unit from a single manufacturer because of the standardization and close coordination required among the various components. Should it ever become necessary or desirable to obtain portions from different manufacturers, careful coordination must be maintained. Separate procurement would not normally be undertaken except for future add-ons, where the original manufacturer may be unable to deliver as required.

b. Specification

Any specification for metal-clad switchgear should include the following information or requirements:

(1) Switching Scheme Selection and One Line Diagram

Practically any desired switching scheme is available. The choice should be made based on system requirements and cost.

(2) Available Fault and Continuous Currents for Breaker Selection

Anything affecting the circuit breaker requirements should be mentioned, such as reclosing duty, operating voltage, capacitor or reactor switching, etc.

(3) Main Bus Rating Selection

Standard ratings match the continuous current rating of available circuit breakers. Judicious arrangements of "source" and "load" breakers can result in the lowest bus current requirements. Future expansion should be considered.

(4) Current and Potential Transformer Selection

Each transformer should be located on the one line diagram and its requirements described.

(5) Relay and Control Function Selection

To ensure that the metal-clad switchgear is wired by the manufacturer as desired and sufficient space is provided for all equipment, it is vital that the engineer detail the types of relays, control schemes, interlocks, metering and interconnection features that he wants incorporated. This usually involves a cubicle by cubicle list of materials to be furnished. It may also include schematic diagrams when requirements are complex.

(6) Closing, Tripping and Power Requirements

(7) Special Requirements of Temperature, Altitude, Unusual Atmospheric Contamination, Vibration, Etc.

Standard conditions are for operation in air at nameplate ratings within -30°C and +40°C and at

altitudes not exceeding 1,000 meters (3,300 feet).

(8) Physical Sketch of Desired Arrangement, Orientation, Mounting Requirements, Indoor or Outdoor Type, Etc.

(9) Itemized List of Requirements

This list should clearly state all requirements for equipment in each cubicle and include the number of spare breakers and test equipment to be provided, etc.

REFERENCES

Number	ANSI Standards or Guides
C37.03, .04, .04a	A-C Power Circuit Breakers Definitions and Rating Structure
-	Rms Value of A Sinusoidal Current Wave and a Normal-Frequency Recovery Voltage, Methods for Determining
C37.05	Values of a Sinusoidal Current Wave and a Normal-Frequency Recovery Voltage, Methods for Determining
C37.06, .06a	Preferred Ratings of Power Circuit Breakers
C37.07	Interrupting Factors - Reclosing Service
(See C37.06)	Rated Control Voltages
C37.09, .09a	Test Code for Power Circuit Breakers
C37.010	Application Guide
-	Power Circuit Breaker Control
-	Guide Specifications
C37.1	Relays Associated with Electric Power Apparatus
C37.2	Automatic Station Control, Supervisory and Associated Telemetering Equipment (Includes Device Function Description)
C37.20	Switchgear Assemblies and Metal-Enclosed Bus (IEEE-27)

Number	NEMA Standards
SG-2	Standards for High-Voltage Fuses
SG-4	Standards for Power Circuit Breakers
SG-5	Standards for Power Switchgear Assemblies
SG-6	Standards for Power Switchgear Equipment

APPENDIX

TO

METAL-CLAD SWITCHGEAR

Table 1

Voltages and Insulation Levels, AC Switchgear Assemblies

Voltages (rms)		Insulation Levels (kV)		
Nominal Voltage	Rated Maximum Voltage	Power Frequency Withstand (rms)	DC Withstand*	Impulse Withstand
Metal-Enclosed Low-Voltage Power Circuit Breaker Switchgear				
Volts	Volts			
240	254	2.2	3.1	—
480	508	2.2	3.1	—
600	635	2.2	3.1	—
Metal Clad Switchgear				
kV	kV			
4.16	4.76	19	27	60
7.2	8.25	36	50	95
13.8	15.0	36	50	95
34.5	38.0	80	†	150
Metal-Enclosed Interrupter Switchgear				
kV	kV			
4.16	4.76	19	27	60
7.2	8.25	26	37	75
13.8	15.0	36	50	95
14.4	15.5	50	70	110
23.0	25.8	60	†	125
34.5	38.0	80	†	150
Station-Type Cubicle Switchgear				
kV	kV			
14.4	15.5	50	†	110
34.5	38.0	80	†	150
69.0	72.5	160	†	350

*The column headed "DC Withstand" is given as a reference only for those using dc tests and represents values believed to be appropriate and approximately equivalent to the corresponding power frequency withstand test values specified for each voltage class of switchgear. The presence of this column in no way implies any requirement for a dc withstand test on ac equipment. When making dc tests, the voltage should be raised to the test value in discrete steps and held for a period of one minute.

†Because of the variable voltage distribution encountered when making dc withstand tests, the manufacturer should be contacted for recommendations before applying dc withstand tests to the switchgear. Potential transformers above 34.5 kV should be disconnected when testing with dc. Refer to 6.8 of American National Standard Requirements for Instrument Transformers, C57.13-1968, and in particular to 6.8.2 which reads "Periodic kenotron tests should not be applied to transformers of higher than 34.5 kV rating."

Ref 37.20

E. SUBSTATION VOLTAGE REGULATORS

1. General

This section covers voltage regulators, both three phase and single phase, used in distribution substations to regulate the load side voltage. Substation regulators are one of the primary means, along with load-tap-changing power transformers, shunt capacitors and distribution line regulators, for maintaining a proper level of voltage at a customer's service entrance.

A very important function of substation voltage regulation is to correct for supply voltage variation. However, with the proper use of the control settings and line drop compensation, the regulators can do much to correct for load variations as well. A properly applied and controlled voltage regulator not only keeps the voltage at a customer's service entrance within approved limits but also minimizes the range of voltage swing between light and heavy load periods.

The substation regulators may be located on individual feeders or in the transformer secondary circuit for main bus regulation. Normally, the low voltage substation bus will be regulated rather than the individual feeders. Individual feeder regulation can usually be justified only when there are extreme variations between individual distribution feeder peak load times. Very long or heavily loaded distribution feeders may require supplemental regulators, strategically located out on the line, to maintain voltage levels within required limits.

In evaluating the proper application of voltage regulators, reference should be made to REA Bulletin 169-27, "Voltage Regulator Application on Rural Distribution Systems," and to REA Bulletin 169-1, "The Application of Shunt Capacitors to the Rural Electric System."

The voltage levels recommended by REA are given in Bulletin 169-4, "Voltage Levels on Rural Distribution Systems." The recommended levels are based on ANSI C84.1, "Voltage Ratings for Electric Power Systems and Equipment (60 Hertz)."

Regulators for use on REA borrowers' systems must meet the requirements in REA Specification S-2, "Specification for

Substation Regulators, Where Applicable." These specifications apply to step-type single-or three-phase, substation or pole-mounted, outdoor, oil-immersed, self-cooled regulators.

In addition to REA Specification S-2, all regulators must comply with ANSI C57.15, "Requirements, Terminology, and Test Code for Step-Voltage and Induction-Voltage Regulators," and ANSI C57.95, "Guide for Loading Oil-Immersed Step-Voltage and Induction-Voltage Regulators."

2. Types

There are two general types of voltage regulators, the induction regulator and the step-type regulator. Both types are available in single-phase or three-phase designs. The step-type regulator has by far the wider application in the electric distribution system. Quoting from ANSI C57.15, the definitions are:

a. Induction-Voltage Regulator

"An induction-voltage regulator is a regulator having a primary winding in shunt and a secondary winding in series with a circuit for gradually adjusting the voltage or the phase relation, or both, of the circuit by changing the relative position of the exciting and series windings of the regulator."

Changing the relative position of the primary and secondary windings will result in either additive or subtractive voltages of varying magnitudes depending on the direction and amount of change.

b. Step-Voltage Regulator

"A step-voltage regulator is a regulator having one or more windings excited from the system circuit or a separate source and one or more windings connected in series with the system circuit for adjusting the voltage, or the phase relation, or both, in steps, without interrupting the load."

As with the induction regulator, when a voltage is impressed on the primary winding, the magnetic flux linking the secondary or series winding will induce a voltage in the series winding.

An automatic reversing switch is incorporated to obtain an additive or subtractive voltage from the series winding with respect to the primary voltage. Taps of the series winding are connected to an automatic tap-changing mechanism to regulate the amount of voltage change in equal steps.

The terminal designations of step-type voltage regulators are as follows: The terminal connected to the load is designated L, the terminal connected to the source is designated S, and the common terminal is designated SL. For three-phase regulators, these identifications are S1, S2, S3, L1, L2, L3 and S_0L_0. This is illustrated in Figure 3 of REA Bulletin 169-27.

c. Single-Phase Versus Three-Phase

Several factors influence the selection: For the sizes of substations used most frequently by rural electric systems, single-phase regulators are usually less expensive than either of the other methods. They also are more able to maintain balanced phase voltages under conditions of unbalanced loading. Single-phase regulators are also more adaptable to line use because of the relative ease of pole mounting. Regulation by single-phase regulators also gives maximum reliability for the system because a regulator can be removed for maintenance or repair without the need to deenergize transformers or other regulators. Special switches are available to permit removing a regulator from service without interrupting the circuit. These should always be provided.

In large distribution substations, the choice of three-phase regulators may be based on costs or on the nonavailability of single-phase regulators of the required size. Three-phase regulators require somewhat less space than three single-phase regulators, although this is not generally a major factor in selection.

Load tap changing power transformers are being increasingly used in distribution substations. They consist essentially of a three-phase regulator built into a three-phase power transformer. The relative cost of this combination compared to a separate transformer and either three-phase or single-phase regulators varies depending on the size of the substation.

Aside from the base cost of the equipment, the LTC method generally will result in a saving in space, buswork and supporting structures.
Because their controls sense only one phase of a three-phase circuit and since some unbalance may be expected among the phases, the voltage correction of three-phase regulators and LTC transformers will be less precise than that of single-phase regulators.

Regardless of the selection of single-phase or three-phase regulators, a spare regulator for each substation is normally not justified.

3. Ratings

a. kVA Rating

The kVA rating of a single-phase regulator is the product of its rated load amperes and its rated range of regulation in kilovolts. For polyphase regulators, this product must be multiplied by the appropriate phase factors (1.732 for three-phase regulators). The kVA rating of a 10 percent, 7620 volt, single-phase regulator capable of carrying a rated load current of 100 amperes would be:

$$kVA = 7.620 \times .10 \times 100 = 76.2 \text{ kVA}$$

In those cases where the range of regulation is different for the "raise" position than for the "lower" position, the larger percent regulation is used to determine the regulator kVA rating.

The ratings for regulators generally are based upon operation at 60 Hz with a range of regulation of 10 percent "raise" and 10 percent "lower" without exceeding the specified temperature rise at the given operating voltage. Regulator losses decrease as the regulator moves from the extreme tap positions (boost or buck) closer to the neutral point. Since the range of regulation required need not always be a full 10 percent, this allows for an extended range of regulator operation.

This is shown in the tabulation below for single-phase step regulators rated 19.9 kV and below.

Range of Voltage Regulation (Percent)	Amperes as Percent of Rated Current *
± 10	100
± 8.75	110
± 7.50	120
± 6.25	135
± 5.00	160

* Maximum Current 668 Amperes

For three-phase, step-voltage regulators rated 13.8 kV and below, the extended range of regulation is as follows:

Range of Voltage Regulation (Percent)	Amperes as Percent of Rated Current **
± 10	100
± 8.75	108
± 7.50	115
± 6.25	120
± 5.00	130

** Maximum Current 600 Amperes

It can be seen from the above tabulations that if regulators are applied to circuits requiring only five percent regulation, their current carrying capabilities can be extended to provide additional capacity - up to 160 percent in the case of single-phase regulators.

b. Voltage

Preferred voltage ratings of step-voltage and induction-voltage regulators based on a voltage range of ten percent raise and ten percent lower are given in Tables 5, 6, 7, 8 (see Appendix) of ANSI Standard C57.15.

Substation regulators should be specified as being capable of providing a range of voltage regulation of plus or minus ten percent and a bandwidth not greater than plus and minus one volt (on a 120 volt base).

Most regulators are specified with a $\pm$ 10 percent range using 32 - 5/8 percent steps.

c. Current

Preferred current ratings of step-voltage and induction-voltage regulators are listed in the Tables 5, 6, 7, 8 (see Appendix) of ANSI Standard C57.15.

d. Temperature

ANSI Standard ratings of kVA, voltage and current for air cooled voltage regulators are based on ambient air temperature not exceeding 40°C and on the average temperature of the cooling air for any 24-hour period not exceeding 30°C. For loading under other conditions, see Guide for loading Oil-Immersed Step-Voltage and Induction-Voltage Regulators, Appendix of ANSI C57.97.

The ratings are based on a temperature rise above the ambient in accordance with Table 4 (see Appendix) of ANSI Standard C57.15.

e. Altitude

ANSI Standard ratings of voltage regulators are based on an altitude not exceeding 1,000 meters (3300 feet). At higher altitudes, the decreased air density has an adverse effect on the temperature rise and the dielectric strength of voltage regulators.

Tables 2 and 3 (see Appendix) of ANSI C57.15 give a basis for loading above 1000 meters. Also, see Guide for loading Oil-Immersed Voltage Regulators, Appendix of ANSI C57.95.

Table 1 (see Appendix) of ANSI C57.15 gives correction factors for dielectric strength at altitudes above 1000 meters.

f. Short Circuit Strength

Regulators used on REA borrowers' systems must be capable of withstanding rms symmetrical short-circuit currents of 25 times the regulator full-load current for two seconds and 40 times the regulator full-load current for 0.8 seconds without injury.

Where short-circuit duty on the regulator exceeds its capabilities, current limiting reactors may be installed in the substation to limit the available fault current.

4. Regulator Controls

a. General

Regulators are equipped with a number of devices and controls that allow the operator to use the regulator effectively. These include means for setting or adjusting the voltage level, bandwidth, time delay, range of regulation and line drop compensation.

Since a change in the setting of any one of these devices will directly affect the operation of one or more of the other devices, they are all treated as a unit comprising what is known as the regulator control system. In earlier regulators, the components of this control system were of the electromechanical type, but regulators manufactured since about 1963 are equipped with static-type devices featuring solid state components. The setting of the individual devices in the newer control systems is based upon the same principles. They are, in general, easier to set than the older mechanical type.

The various devices used in the control system are almost all adjusted at the control panel. One exception is the range of regulation, which is made at the position indicator mounted on the regulator. The control panel can be mounted directly on the regulator or remote from the regulator.

For a brief description of the control devices and the settings recommended by REA, refer to Bulletin 169-27.

b. Control System Accuracy

The individual components utilized in the regulator control system are accurate devices, and as such, they enable the regulator to obtain a level of efficiency sufficient to meet Class I accuracy requirements. Class I accuracy means that the sum of errors in the control circuit taken individually cannot total more than plus or minus one percent. A plus error would be one causing the regulator output to be higher than the reference value, while a minus error would be one causing the regulator output to be lower than the reference value.

Because of this accuracy and, more importantly, because of its function in maintaining system voltage levels, the voltmeters and other instruments used in conjunction with regulators should be as accurate as the regulator. To utilize measuring equipment any less efficient than this deprives the system of the regulator's full capabilities. (See REA Bulletin 161-7, "Guide for Making Voltage Measurements on Rural Distribution Systems.")

5. Lightning Protection

Voltage regulators, like other elements of the distribution system, require protection from lightning and other high voltage surges. Because voltage regulators are constructed like autotransformers, having one of the windings in series with the primary line, additional protection is required for this series winding. Regulators are normally factory equipped with bypass arresters across this series winding; these arresters

may be connected internally or externally, depending upon the manufacturer. The bypass arrester limits the voltage developed across the series winding during surges to within safe values. <u>CAUTION</u>: Bypass arresters protect only the series winding of the regulator and do not eliminate the need for arresters to protect the regulator itself.

APPENDIX

TO

SUBSTATION VOLTAGE REGULATORS

Table 1
Dielectric Strength Correction Factors for Altitudes Greater Than 3,300 Feet (1,000 Meters)

Altitude Feet	Altitude Meters	Altitude Correction Factor for Dielectric Strength
3,300	1,000	1.00
4,000	1,200	0.98
5,000	1,500	0.95
6,000	1,800	0.92
7,000	2,100	0.89
8,000	2,400	0.86
9,000	2,700	0.83
10,000	3,000	0.80
12,000	3,600	0.75
14,000	4,200	0.70
15,000	4,500	0.67

NOTE: Altitude of 15,000 feet is considered a maximum for standard regulators.

Table 2
Maximum Allowable Average Temperature of Cooling Air for Carrying Rated Load in kVA

Method of Cooling	3,300 Feet (1,000 Meters)	6,600 Feet (2,000 Meters)	9,900 Feet (3,000 Meters)	13,200 Feet (4,000 Meters)
Oil-Immersed Self-Cooled	30	28	25	23
Oil-Immersed Forced-Air-Cooled	30	26	23	20
Oil-Immersed Forced-Oil-Cooled with Oil to Air Cooler	30	26	23	20
Dry-Type Self-Cooled				
(1) 55°C Rise	30	27	24	21
(2) 80°C Rise	30	26	22	18
(3) 150°C Rise	30	22	15	7
Dry-Type Forced-Air-Cooled				
(1) 55°C Rise	30	24	19	14
(2) 80°C Rise	30	22	14	6
(3) 150°C Rise	30	15	0	−15

NOTE 1: See 3.1 for explanation of average temperature.
NOTE 2: All temperatures are in degrees C.

Ref. C57.15

Table 3
Rating in kVA Correction Factors for Altitudes Greater Than 3,300 Feet (1,000 Meters)

Types of Cooling	Correction Factor, Percent
Oil-Immersed Self-Cooled	0.4
Oil-Immersed Water-Cooled	0.0
Oil-Immersed Forced-Air-Cooled	0.5
Oil-Immersed Forced-Oil-Cooled with Oil to Air Cooler	0.5
Oil-Immersed Forced-Oil-Cooled with Oil to Water Cooler	0.0
Dry-Type Self-Cooled	0.3
Dry-Type Forced-Air-Cooled	0.5

Table 4
Limits of Temperature Rise

Item	Type of Apparatus*	Winding Temperature Rise by Resistance, Degrees C	Hottest-Spot Winding Temperature Rise, Degrees C
(1)	55° C Rise Oil-Immersed	55	65
	55° C Rise Dry-Type	55	65
	80° C Rise Dry-Type	80	110
	150° C Rise Dry-Type	150	180
(2)	Metallic parts in contact with or adjacent to the insulation shall not attain a temperature in excess of that allowed for the hottest spot of the windings adjacent to that insulation.		
(3)	Metallic parts other than those covered in Item (2) shall not attain excessive temperature rises.		
(4)	Where regulator is provided with sealed-tank, conservator, gas-oil-seal, or inert-gas-pressure systems, the temperature rise of the insulating oil shall not exceed 55° C when measured near the top of the main regulator tank. The temperature rise of insulating oil in regulator not provided with the oil preservation systems listed above shall not exceed 50° C when measured near the exposed surface of the oil.		

*Apparatus with specified temperature rise shall have an insulation system which has been proven by experience, general acceptance or accepted test.

Ref. C57.15

Table 5
Preferred Ratings for Oil-Immersed Self-Cooled Induction-Voltage Regulators (Single-Phase)

Volts	Insulation Class	kVA	Line Amperes
2,500	2.5	37.5	150
		50	200
		62.5	250
		75	300
		100	400
		125	500
		167	668
		200	800
5,000	8.66	37.5	75
		50	100
		62.5	125
		75	150
		100	200
		125	250
		167	334
		200	400
		300	600
7,620	15.0	76.2	100
		114.3	150
		167	219
		200	262

Table 6
Preferred Ratings for Oil-Immersed Self-Cooled Induction-Voltage Regulators (Three-Phase)

Volts	Insulation Class	kVA	Line Amperes
2,500	2.5	375	866
		500	1,155
4,330	5.0	375	500
		500	667
5,000	5.0	375	433
		500	577
13,800	15.0	375	157
		500	209

Ref. C57.15

Table 7
Preferred Ratings for Oil-Immersed Self-Cooled Step-Voltage Regulators (Single-Phase)

Volts	Insulation Class	kVA	Line Amperes
2,500	5.0	50	200
		75	300
		100	400
		125	500
		167	668
		250	1,000
		333	1,332
5,000	8.66	50	100
		75	150
		100	200
		125	250
		167	334
		250	500
		333	668
7,620	15	38.1	50
		57.2	75
		76.2	100
		114.3	150
		167	219
		250	328
		333	438
13,800	15	34.5	25
		69	50
		138	100
14,400	25*	36	25
		72	50
		144	100
		288	200
19,920	25*	100	50.2
		200	100.4
		400	200.8

*Low-frequency test voltage 50 kV by induced test with neutral grounded.

Ref. C57.15

Table 8
Preferred Ratings for Oil-Immersed Step-Voltage Regulators
(Three-Phase)

Volts	Insulation Class	Self-Cooled		Self-Cooled/Forced-Cooled	
		kVA	Line Amperes	kVA	Line Amperes
2,500	2.5	500	1,155	625	1,443
		750	1,732	937	2,165
		1,000	2,309	1,250	2,887
4,330	5.0	500	667	625	833
		750	1,000	937	1,250
		1,000	1,334	1,250	1,667
5,000	5.0	500	577	625	721
		750	866	937	1,082
		1,000	1,155	1,250	1,443
8,660	8.66	500	333	625	417
		750	500	900	600
13,200	15	500	219	625	274
		750	328	938	410
		1,000	437	1,250	546
		1,500	656	2,000	874
13,800	15	500	209	625	261
		750	313	937	391
		1,000	418	1,250	523
		1,500	628	2,000	837
		2,000	837	2,667	1,116
		2,500	1,046	3,333	1,394
23,000	25	500	125.5	625	156.8
		750	188.3	937	235.4
		1,000	251	1,250	314
		1,500	377	2,000	502
		2,000	502	2,667	669
		2,500	628	3,333	837
34,500	34.5	500	83.7	625	104.6
		750	125.5	937	156.8
		1,000	167	1,250	209
		1,500	251	2,000	335
		2,000	335	2,667	447
		2,500	418	3,333	557
46,000	46	500	62.8	625	78.5
		750	94.1	937	117.6
		1,000	126	1,250	157
		1,500	188	2,000	251
		2,000	251	2,667	335
		2,500	314	3,333	419
69,000	69	500	41.8	625	52.5
		750	62.8	937	78.5
		1,000	83.7	1,250	105
		1,500	126	2,000	167
		2,000	167	2,667	223
		2,500	209	3,333	278

Ref. C57.15

F. SHUNT CAPACITOR EQUIPMENT

1. General

This section deals with outdoor shunt capacitor equipment of the open-rack type located at substations. Their function is to improve power factor and voltage conditions by providing leading kilovars to transmission and distribution systems. For the criteria to determine the need for capacitors and selecting size, location, etc., refer to REA Bulletin 169-1, "The Application of Shunt Capacitors to the Rural Electric System."

REA Bulletin 43-5, "List of Materials for Use on Systems of REA Electrification Borrowers," should be consulted for accepted manufacturer's types of individual capacitor units. The industry standards for shunt capacitors, ANSI C55.1 (IEEE No. 18) "Shunt Power Capacitors" and NEMA CP-1 "Standards Publication - Shunt Capacitors," should be considered in the application of shunt capacitors. See Appendix, Figure V-6, for a typical capacitor bank arrangement.

2. Types

Substation capacitor equipment can be furnished with all phases in a single rack or with only one phase in a single rack. The largest standard "upright" rack usually holds 40 capacitor units and the largest "edge-mount" rack usually 32 units. These racks are generally furnished complete with individual capacitor units, unit fuses, insulators, supporting structure and other equipment necessary for a complete installation.

For most substation applications in open racks, the individual capacitor units are equipped with only one bushing. The second bushing is often unnecessary when the racks themselves form a part of the circuit and are insulated by means of base insulators. In a three phase delta connected rack, however, two bushing units are required.

Information regarding capacitor impregnant fluids is in the bibliography at the end of this section. In the event any askerel or askerel contaminated materials must be disposed of, the procedures outlined in ANSI C107.1 should be carefully followed.

3. Ratings

a. Circuit Voltage

Domestic manufacturers can supply individual capacitor units in voltages ranging from 2.4 to 25 kV. Units of the same or of different voltage ratings can be mixed to obtain the required circuit voltage. Most REA borrowers utilize capacitor equipments at or above 7.2 kV.

The desired circuit voltage is obtained by connecting as many capacitor sections in series as necessary to obtain the required voltage. Usually, the best engineering choice is to use the minimum number of series sections possible. However, inventory or other economic considerations may override this rule. In general, the bank thus formed is connected in wye.

Where only one series section of paralleled capacitors per phase is used and connected either three phase grounded wye or delta, the unit capacitor fuse is subjected to full system short circuit available current when its associated unit fails. Modern power systems often require that the more expensive, high interrupting capacity, current limiting fuses be applied in these situations. Current limiting fuses should be considered where potential fault currents exceed 4 kA.

One advantage of these connections is that they can be provided in very small sizes without encountering unacceptable overvoltages on the remaining capacitors in a phase when one or more capacitors in that phase fail and clear. This simplifies the protection scheme. Also, the racks themselves do not have to be insulated from ground, thus saving the cost of base insulators.

When a three phase wye connection is used with only one series section of paralleled units per phase, it is advantageous from a fusing standpoint to leave the neutral floating. This allows the unfaulted phases to limit the fault current supplied to the faulted phase. The fuse on the faulted unit will "see" a maximum of only three times normal bank phase current. While this may still be considerable current for large equipment, it is far less than usually available

from the system, and a much less expensive, low interrupting capacity fuse can be applied. A (low) calculated risk is taken of simultaneous failure of units in different phases. It should be noted that, in a floating wye connection, the neutral must have full line insulation between it and ground as well as sufficient ground clearances.

Double-wye is often used when large amounts of kVAR are desired and the equipment is to be equipped with low interrupting capacity expulsion fuses. If the neutrals of the double wye are tied together, the current limiting effect only exists for multiple series section equipment. The effect on a single series section capacitor equipment, under these conditions, would be simply to double the number of capacitor units in parallel. The presence of a CT in the neutral tie does not change this situation, since the impedance of a CT primary is negligible. See Figure V-7 for a typical Y-Y connected capacitor bank with one series section per phase and neutrals isolated.

Delta connected capacitor banks are generally applied only on lower voltage (23 kV or below) circuits, where the circuit voltage equals the voltage rating of a unit capacitor. They must also be properly insulated from ground.

It is important in any capacitor installation to ensure that the maximum operating voltages do not exceed 110 percent of the rated voltage of any capacitor. Because of this, the number of parallel capacitor units in each series section is selected so that the loss of any one unit in any series section will not result in such overvoltage.

b. <u>kVAR Rating</u>

Unit capacitor kVAR ratings available from domestic manufacturers undergo frequent change in order to provide the most practical and economical sizes for current conditions. In general, the trend is toward larger unit sizes. Unit kVAR sizes currently listed for substation rack application are: 50, 100, 150 and 200. Obsolete sizes may sometimes be made for replacement purposes.

The capacitor manufacturer's recommendations should be considered in determining the optimum size of capacitor unit, number of series sections, number of units in parallel and type of connection to make up the kVAR requirement of a given installation.

c. Basic Insulation Level

Basic impulse insulation levels (BIL) of individual capacitor units range from 75 to 150 kV. Typically, 8.67 kV class (4501-8000V) units would require 75 kV BIL, 15 kV class (8001-15000V) units would require a minimum 95 kV BIL, and 15001-23000V units would require 125 kV BIL.

d. Temperature

The maximum allowable ambient temperature for capacitor equipments installed outdoors with unrestricted ventilation is 40°C (104°F). It should be noted that the 40°C is the arithmetic average of hourly readings during the hottest days expected at the site. Isolated, multiple row and tiers and metal-enclosed or housed units will have maximum ambient ratings of 46°C, 35°C and 35°C, respectively. Capacitors are suitable for energization at temperatures down to -40°C (-40°F). Where the expected in-service ambient temperatures are lower than -40°C, the manufacturer should be consulted.

4. Switching

a. Switching Devices

The various devices that may be used for capacitor switching include the following:

Circuit Breakers	Interrupter Switches
Air	Oil
Air-Magnetic	SF_6
Oil	Vacuum
SF_6	
Vacuum	

All capacitor switching devices should be applied within their maximum voltage, frequency, and current ratings, including transient inrush current and frequency. Since capacitors can be operated continuously up to 10 percent above the capacitor rated voltage, and capacitor operation causes a voltage rise, the maximum voltages (110 percent rated) should be used.

The current rating of the switching device should include the effects of overvoltage (1.1), capacitor tolerance (1.05 to 1.15) and harmonic component (1.05 for ungrounded capacitor bank, 1.1 for grounded capacitor bank). It is usually considered adequate to use a total multiplier of 1.25 for ungrounded operation and 1.35 for grounded operation. (ANSI C37.0731 Capacitor Current Switching Guide).

Most switching devices are derated for capacitor switching to a value well below the continuous current rating.

See Reference 20 for characteristics of capacitor switching devices and for discussions of inrush currents, transient overvoltage and the effect of parallel banks.

b. Controls

Controls for capacitor switching devices may operate in response to various signals such as voltage, current, VAR, temperature, time or some combination of these. A variety of options is available in terms of price, features and quality. These range from high price panel-mounted to low price socket-mounted controls. In recent years, capacitor controls based on electromechanical relays have been superseded by more modern electronic types. See Figures V-2, 3, 4, 5 for typical schematics of various capacitor control arrangements.

Control and application of capacitors are such closely related subjects that a discussion of one must necessarily involve the other. In fact, in the typical situation, both the type of control and its adjustment are dictated by the objectives of the capacitor installation.

Capacitor controls are basically single pole, double throw switches activated by a signal(s) selected to reflect kVAR requirements. Theoretically, at least, any intelligence that changes only when a change in the kVAR supply is needed can be utilized to switch capacitors automatically. In practice, however, selecting a signal that accurately reflects the requirements of the feeder often turns out to be the most difficult part of the problem. The single input types, such as voltage and time controls, are generally less expensive in initial cost and installation, less complex and easier to adjust but less flexible in application than the dual-input types such as kilovar and current biased voltage controls.

The selection of a control for a particular switched capacitor bank requires careful evaluation of several related factors. Some of the more important considerations are listed below. No attempt has been made to list them in any particular order, since their relative importance and probably even the factors themselves will vary considerably from one system to another.

> Purpose for which bank is being installed (to reduce losses, improve voltage under normal or emergency operating conditions, reduce thermal loading of lines and equipment, etc.).
>
> Location on feeder (whether voltage will drop appreciably as load increases, whether direction of feed is likely to change frequently because of normal or emergency circuit rearrangements, etc.).
>
> Coordination with other switched capacitors or voltage regulators.
>
> Cost of control and auxiliary equipment (operating transformer, control secondary, current transformer, etc.).

The optimum choice of control will always be the least expensive type that will switch the capacitor bank on the required schedule. To facilitate comparison, the operating characteristics and relative cost of some common types used are summarized below:

COMPARISON OF OPERATING CHARACTERISTICS

OF CAPACITOR CONTROLS

Type of Control	Advantages	Disadvantages
Time	Non-electrical input allows application at any point on the circuit.	Cannot be applied on feeders where kVAR load does not have a regular daily variation that is repeated weekly. Use limited to locations where established switching schedule will not cause high voltage on holidays or during other abnormally light load periods. Insensitive to abnormal voltage conditions.
Voltage	Responds to abnormal voltage conditions.	Can only be applied where voltage drops appreciably under load. More difficult to coordinate with voltage regulators and other switched capacitor banks. Requires separate potential transformer.
Kilovar	Most effective in minimizing losses because it senses fundamental quantity being corrected (kVAR). Current and voltage sources available for general testing on feeder.	Directional (reversing direction of feed will reverse signal). Insensitive to abnormal voltage conditions. Requires current transformer and potential transformer.
Current	Can be applied at any point on the circuit where the load current can be monitored. Nondirectional. Responds to current changes. Current and voltage source available for general testing on feeder.	Requires current transformer and separate potential transformer. Adjustment slightly more complex than other controls.

Type of Control	Advantages	Disadvantages
Manual	No control device necessary; the switch is operated by substation personnel.	Requires attendants at the substation.

(1) Manual

The simplest means to accomplish capacitor bank switching is the manual control. Substation personnel, observing the need for capacitor banks to be switched, either go out to the yard and physically operate the switching devices or operate them remotely from a panel.

(2) Time Controls

REA borrowers wishing to relieve their personnel of the responsibility for manual capacitor bank control can substitute automatic controls. One of the most economical automatic controls is the time device. Time control switches the capacitor bank on or off at a fixed time each day. It usually takes the form of a clock that operates on station service ac. It may include provisions for omitting control on weekends. Time control is most useful when the reactive load is periodic and predictable. This should be determined by examining the daily load curves. The time control does not require the monitoring of any electrical quantities.

(3) Temperature Controls

In certain areas of the country, the reactive load is more closely aligned with temperature variation than with anything else. Such loads do not exhibit the periodicity that would suggest the use of time clocks. They are often associated with the operation of air conditioners. Such a load would suggest the use of a temperature control. A thermostat in the temperature control responds to changes in ambient temperature to provide input to the switching device. A dependent relationship between kVAR load and air temperature should be

determined. As with time controls, these devices are relatively economical and do not require the monitoring of electrical quantities.

(4) Voltage Controls

The most straightforward and simplest of the controls that respond to changes in electrical conditions is the voltage control.

The voltage found at a point on an electrical system is the summation of all conditions on the system. Capacitors increase the voltage at the point where they are applied. Thus, a low voltage would suggest the need for capacitors, and a high voltage would call for their removal. This would not be true at a location close to the output of a compensated regulator where high voltage is developed with peak loads. A simple capacitor control based only on voltage would not give the desired results if applied in a segment of the system where compensation in regulators cancelled the significance of high and low voltage as an indicator of loads. The bandwidth of the control should be larger than the voltage change caused by switching of the capacitor bank to prevent hunting.

Voltage controls usually respond to signals from a nominal 120 volt source ranging between 108 and 132 volts. If the switching device is a vacuum switch, the primary of the VT monitoring voltage should be protected by means of a distribution class surge arrester. This protects against high voltages produced by the chopping effect of the switches.

(5) Current Controls

A simple answer to many of the desired objectives of capacitor control is the measurement and subsequent switching of the capacitors according to the flow of current. This solution is particularly attractive on circuits consisting primarily of a known group of electric motors. Typical examples would be a circuit for pumps on a major water supply or for irrigation, driven by electric motors and located a considerable distance from

the source or on any application where there is a dependent relationship of reactive (kVAR) load with current.

Heavy loads on circuits of this type could occur at any time of day or night and any day of the week. Capacitors used on this application would be dedicated to serving these motor loads. Switching of the capacitors is, therefore, logically a function of these loads.

Current controls are sensitive to signals between 0.5 and 5 amperes from a 5 ampere CT secondary. As a safety feature to protect against high secondary open circuit voltages, the control should be arranged to short circuit the CT secondary leads automatically when the control circuit is opened.

In some instances several banks of capacitors are placed in the same substation to facilitate incremental application of kVAR to the bus. They might, for example, have a fixed capacitor bank and two switched banks controlled by a two-step voltage control. In addition to the care necessary in setting multi-step controls to avoid "hunting," discussed below under VAR Controls, the capacitor switches should be selected with the aim of protecting them from the consequences of back-to-back capacitor switching. This is also discussed in Paragraph 4.

In addition to the above controls, there are a number of combination types, of which the most common are Time-and-Temperature, and Voltage-with-Current-Bias.

(6) VAR Controls

The most sophisticated of the line of controls, that responds directly to VAR demand, is the VAR control.

Care must be taken to set the control so that the response of the system to the presence or absence of the capacitor bank is less than the bandwidth represented by the maximums and minimums of the settings on the control. For example, if

a 2100 kVAR bank of capacitors is applied, the "turn off" setting of the control should be greater than the "turn on" setting + 2100 kVAR. This is necessary to prevent hunting.

VAR controls are usually arranged to respond to signals from a VT with a secondary rating of 120 volts connected across two phases and a CT with a secondary rating of 5 amperes in the third phase. This arrangement provides a 90 degree phase angle between the voltage and the current signals at unity power factor.

Some VAR controls have capacitors in either the voltage or current inputs to retard the phase angle and thus to make it possible to read VAR signals by monitoring fewer than three phases.

(7) Protective Controls

Capacitor switching devices are also arranged to operate in response to signals from protective controls. These are described further under "Protection."

c. Control Power

(1) Wiring

When more than one control is provided, the capacitor manufacturer should be instructed to arrange for all secondary circuits to be run to a common junction box to facilitate field connections.

(2) Source

Most controls with lockout relays require nominal 120 volt ac for operation, but they can be arranged for other voltages. The switches that are controlled, however, may be ac or dc at any number of voltages. The capacitor manufacturer should be told the control voltages available at the installation.

(3) Transfer and Control Switches

Many controls have selector switches for "automatic or manual" operation and for "local or remote" location. When the "local-remote" switch is set for "local" and the "automatic-manual" switch is set for "manual," the capacitor switching device may be controlled from the local control cabinet. If the "automatic-manual" switch is set for "automatic," the capacitor switching device will respond to the control signals, unless a protective override opens the device and locks it out.

d. Switching Arrangements

(1) Single Bank

The transient inrush current to a single isolated bank is less than the available short circuit current at the capacitor location. Since a circuit breaker must meet the momentary current requirement of the system, transient inrush current is not a limiting factor in the isolated capacitor bank -breaker application. However, the momentary rating of other switching devices not intended for fault current interruption should be checked.

(2) Back-to-Back Switching

Capacitor bank switching devices are often limited in their short circuit interrupting ratings. However, when capacitor banks are switched back-to-back (one being energized when another is already connected to the same bus), transient currents of high magnitude and high frequency may flow between the banks on closing of the switching device or in the event of a restrike on opening. See Figure V-5 for a typical arrangement of two capacitor banks switched back-to-back. The oscillatory current is limited only by the impedance of the capacitor banks and the circuit between them. The transient current usually decays to zero in a fraction of a cycle of the power frequency. The component supplied by the power source is usually so small it may be neglected.

The magnetic fields associated with high inrush currents during back-to-back switching in either the overhead conductors or the grounding grid can induce voltages in control cables by both electrostatic and electromagnetic coupling. These induced voltages can be minimized by shielding the cables, using a radial configuration for circuits (circuits completely contained within one cable so inductive loops are not formed), and single point or peninsula grounding of the capacitor banks. (See Reference 19 for definitions of these types of grounding configurations.)

The magnitude and consequent effects of inrush current to a switched capacitor bank may be greatly reduced by using a capacitor switching device furnished with preinsertion resistors.

Sometimes adequate impedance to limit the inrush current to the rating of the switch may be obtained by physically locating the banks as far apart from one another in the substation as possible. In other cases, it may be necessary to provide inductive reactance in the form of current limiting reactors between parallel switched capacitor banks.

To limit the peak inrush current to "kA," in a substation of "n" equal size parallel capacitor banks, of "MVAR," megavars per phase each at "f" Hertz, one should provide a current limiting reactor in each phase of each bank of

$$L_T = \frac{MVAR \cdot 10^6 \cdot (n-1)}{(kA)^2 \cdot \pi \cdot f \cdot n} \text{ Microhenry}$$

(See sample calculation in the Appendix.)

If the capacitor manufacturer determines and supplies all accessory equipment, including switches and reactors, it is necessary to inform him of the total MVAR in the substation and the inductive reactance of the bus between the capacitor banks. This will enable him to calculate the ratings of any required reactors. When physically locating these reactors, care

should be taken to space them as far apart as practical to minimize the effect of mutual reactance. The reactors' continuous current ratings should be at least equal to the continuous current ratings of the switches they protect. They should meet the requirements of ANSI C57.16.

5. Protection

Additional information on capacitor bank protection can be found in REA Bulletin 169-1.

a. Fuses

(1) General

Electric devices (or circuits) are generally fused for one or both of two basic reasons: (1) to protect the device from overloads; (2) to protect the system from failure within the device. In some cases, such as group fusing with cutouts, the fuse may be used as a manual disconnect or switching means. This is not, however, a basic function of a capacitor fuse. Because capacitors, for economic reasons, are designed for operation at high dielectric stress, a certain calculated failure rate is to be expected. Thus, capacitor unit fuses are used primarily to protect the electrical system from dielectric failures that are expected to occur.

(2) Functional Requirements of Capacitor Fuses

Capacitor fuses must meet the following principal functional requirements:

(a) Isolate a faulted capacitor unit, bank or portion of a bank from the circuit to which it is connected with negligible disturbance to the remainder of the bank or system.

(b) Prevent case rupture by clearing the faulted capacitor from the circuit before the gas generated by the internal fault bursts the capacitor case, possibly to damage adjacent units or equipment, injure personnel or discharge dielectric liquid into the ecosystem.

(c) Indicate the location of the failed capacitor.

(d) Carry normal capacitor overloads, transient inrush currents, discharge currents and rated current without spurious operation and without affecting the ability of the fuse to perform the first three functions.

(3) Types of Application for Capacitor Fuses

There are two general schemes used for external fusing of capacitor banks; i.e., group fusing and individual fusing.

(a) Group Fusing

Within the limits of the four required fuse functions, one fuse may be applied to a group of capacitor units not equipped with individual unit fuses. Generally, other capacitance does not parallel the fuse, and it must operate on 60 Hertz fault current that flows through it. This type of fusing is not often used on substation type capacitor banks.

Group fusing of capacitor banks may be advantageous for relatively small capacitor banks where operation of the fuse, resulting in loss of an entire phase will not have too detrimental an effect on the system. Elimination of the unit fuses permits more compact rack designs and simpler buswork.

However, care should be taken in the application of group fuses to be sure that fault current through the fuse will cause it to operate and clear before the combined system fault current and current discharge from adjacent capacitors into the faulted unit can cause case-bursting.

(b) Individual Fusing

In a capacitor bank or equipment having a number of units connected in parallel, each capacitor unit will usually have its own fuse. Each fuse, therefore, is not only in

series with its capacitor but also in parallel with other capacitors. Often, for multiphase arrangements and various series-parallel groupings, back-up bus fault protection is also provided by either circuit breakers or large power fuses.

With individual fusing, the loss of any individual capacitor does not necessarily result in the loss of the bank, the phase, or even the series section. The adjacent units tend to "dump" into the faulted unit, thus to help the fuse operate quickly to clear the fault. Finally, if for any reason, a reduction needs to be made in the kVAR of the bank, this can be accomplished easily by simply removing the appropriate fuses or links. The spare rack spaces then serve as a storage shelf for the extra capacitors.

(4) Effect of Connections on Capacitor Fuses

The requirements for individual capacitor fuses are affected by the capacitor bank connections as well as the system to which the bank is connected. Non-current limiting fuses, which are cheaper than the current limiting type, can be used wherever bank connections can be arranged to limit the available fault current. Possible capacitor bank connections are:

(a) Three Phase Grounded Wye and Delta

Where only one series section of paralleled units per phase is used, and the equipment is connected three phase grounded wye or delta, the unit fuse is subjected to the full available system short-circuit, whenever a capacitor unit fails. High interrupting capacity, current limiting fuses are required in these situations when the fault current is in the order of 4000 amperes or higher.

(b) Ungrounded Wye

When a three phase wye connection is used with only one series section of paralleled

units per phase and the neutral is left floating, the unfaulted phases will limit the current supplied to the faulted phase from the system. The fuse on the faulted unit will see a maximum of only three times normal bank phase current and generally a less expensive low-interrupting capacity fuse can be used. The small risk of simultaneous failure occurring in units of different phases is usually accepted.

(c) Series - Parallel

Series connected groups of paralled capacitor units are an effective means of limiting fault current to a level where less expensive non-current limiting fuses can be used. The bank voltage rating is the principal factor that determines what series-parallel arrangement to use, along with the type of equipment. Multiple-series-section arrangements are not practical in equipment below 15 kV and in housed equipment. The capacitor manufacturer should be consulted regarding fusing for a specified maximum fault current.

b. Protective Controls

The purpose of protective controls is to remove capacitor banks from the bus before any units are exposed to more than 110 percent of their voltage rating. When capacitor units in a capacitor bank fail, the voltage on the remaining units is a function of the connection of the bank, the number of series sections of capacitors per phase, the number of units in each series section and the number of units removed from one series section. Protective controls are available for grounded neutral capacitor banks, ungrounded neutral capacitor banks and capacitor banks connected wye-wye.

Where the capacitor bank is switched by a circuit breaker, the protective control does not need a lockout relay, since breakers are usually equipped internally with lockout functions. However, where other switching means are provided, the protective control should have a lockout with-manual-reset function.

(1) Grounded Neutral

The most straightforward protective control for grounded neutral capacitor banks is the neutral relaying control. This scheme operates on the neutral current generated because of the unbalance caused by capacitor failures in any phase. It has several shortcomings. The first of these is that third order harmonics must be blocked out of the control, since they will flow in the neutral regardless of whether or not the bank is unbalanced. This blocking is often accomplished by means of a small capacitor in the control that tunes the sensitive element to 60 Hz.

Another shortcoming is that the control is not sensitive to unit failures in different phases. Also, it may be too sensitive and turn off the bank on unit failures in different series sections of the same phase, even though no series section experiences greater than 110 percent overvoltage. Finally, since the associated CT must be large enough to handle continuously the third order harmonics (usually assumed to be 10 percent per phase of fundamental phase current, if no better information is available), the signal at the CT secondary may be too small for relays of ordinary sensitivity. This last shortcoming can be overcome by using 3 CT's, one in each phase, and connecting the secondaries open delta.

The major advantage of the neutral protection scheme is that it is relatively inexpensive. Also, if there aren't too many series sections, the control can be set to alarm and trip before very many units have failed, thereby increasing the probability of valid operation.

(2) Ungrounded Neutral

The floating-neutral protective control is similar to that for the grounded neutral bank, except that a VT is used in the neutral (usually rated 15 kV) to indicate neutral voltage shift on loss of units. The control is voltage sensitive and subject to the same limitations and advantages as the protective control for grounded neutral capacitor banks.

(3) Wye-Wye

The wye-wye capacitor bank may be protected by means of a CT between the two ungrounded neutrals. Caution should be used, however, for this application, since the impedance of a CT primary is negligible and, if the wye-wye bank has one series section, the actual number of capacitors in each phase may be sufficient to exceed the interrupting rating of the unit fuses. This scheme tends to be fairly sensitive, and the CT does not require gap protection, even if a vacuum switch is used. The buswork, however, can be difficult to design.

c. Protection of Current and Voltage Transformers Installed in Capacitor Banks

(1) Current Transformers

When a capacitor bank is connected wye-wye, with a current transformer (CT) in the neutral between the wyes, it is unnecessary to provide external protection for the current transformer. However, for CT's in the line side or in the neutral of a grounded wye bank, where high frequency inrush currents may be expected as a result of vacuum switch operation or for other reasons, it is advisable to provide protection for the CT. This protection normally takes the form of spark gaps or protector tubes.

For CT ratings of under 23 kV and under 600:5 amp, the recommended practice is to provide gaps or protector tubes on both the primary and secondary. For other CT ratings, only the CT secondary need be protected. Since practices vary among capacitor manufacturers, the manufacturer should be consulted about the size and make of the gap or protector tube.

(2) Voltage Transformers

When a voltage transformer (VT) is installed in the neutral of a capacitor bank, it is often advisable to place a surge arrester at the high side of its primary to prevent the capacitor bank base insulators from arcing under voltage

surge conditions. Such voltage surges tend to occur as a result of vacuum switch operation, when the last pole of the vacuum switch to operate is delayed long enough for the VT primary to saturate. This time is on the order of a half cycle or less.

The insulator arcing can be avoided by using full line voltage insulation with the arrester still used to protect the VT.

d. Bird-Proofing

In some cases substation capacitor outages have been caused by faults originated by birds or animals bridging live parts or live parts-to-ground. One straightforward prevention of this is to use edge-mounted equipment, since the electrical clearances in the racks used in this equipment are sufficiently liberal and make it highly unlikely that any bird or animal will be large enough to bridge any of the live parts.

However, if upright racks are used and birdproofing is deemed necessary, there are insulating materials on the market that have been successfully used in the past. They are rubber-like compounds, extruded in structural shapes that give a neat appearance and are easy to apply. Capacitor manufacturers can apply birdproofing at the factory, or it can be applied in the field.

e. Lightning

It is assumed that capacitor banks installed in a substation will be protected from lightning and switching surges by the same devices that protect the rest of the substation. The base and stack insulators, however, should be coordinated with the rest of the substation insulation for effective lightning and switching surge protection.

f. Corona

For systems with voltages above 100 kV, the capacitor manufacturer should be consulted about the advisability of providing corona shields.

6. Grounding and Short-Circuiting of Capacitor Banks

In the United States, ac power capacitors are built with internal discharge resistors so that the residual voltage is reduced to 50 volts or less within five minutes after the capacitor has been disconnected from the source of supply. This is in accordance with NEMA Standard CP-1.

However, it is theoretically possible for the internal discharge device to become disconnected. Since dangerous charges can thus remain at the capacitor terminals, it is usually deemed advisable to provide manually operated switches to short circuit each series section and to ground the capacitor bank after it has been disconnected from the circuit but before it is handled by personnel.

The duty on these switches is not severe and most capacitor manufacturers can supply single hook-stick operated switches to perform both the shorting and grounding functions. While not always required, it may be desirable to specify interlock schemes to prevent the operation of shorting and grounding switches on live circuits and to prevent personnel from entering capacitor-bank areas when the subject banks have not been shorted and grounded.

7. Mounting

In the United States, there are two common positions for mounting capacitor units in outdoor substation racks; i.e., upright and edgemount. These mounting configurations are illustrated in NEMA CP-1, Figures 4-1 and 4-2 (see Appendix).

The upright mounting position is generally preferred for capacitor units up to 10 kV and edgemount for units above 10 kV. Upright racks are relatively compact and provide a metal framework on the outside, which tends to protect the capacitor units. Edgemount units provide ample clearances and protection from bus and bushing flashovers caused by birds, rodents and other causes. They do, however, require more ground space.

In the United States, power capacitors are mounted by means of 2 flanges spaced 39.7 cm (15-5/8 in) apart.

Where units are protected by means of expulsion fuses, it is necessary to provide a minimum of three feet of air clearance plus strike distance between the ends of the

fuses and any grounded metal objects in order to prevent inadvertent flashovers on fuse operation caused by ionized gases contacting the metal objects. For non-expulsion fuses, the additional three feet of clearance is unnecessary.

Normally, capacitor equipment and their substructures are designed to withstand minor earthquake conditions, 129 km/h (80 mph) wind and 1.27 cm (0.5 in) of ice (non-simultaneously). Where conditions are more severe than this, the capacitor manufacturer should be told.

Capacitor racks and housings have provision for mounting of up to three tiers, with no more than two rows of units per tier. There should be unrestricted air circulation around the units. If ambient conditions are extremely dusty, smoky or salty, the capacitor manufacturer should be consulted as to the advisability of extra creep bushings and insulators and more generous strike clearances between live parts.

Capacitor equipments are often mounted on 2.44 m (8 ft.) substructures to provide adequate ground clearance, personnel safety, ventilation and a place to mount accessories. This clearance should be carefully checked and increased if necessary to meet applicable safety codes.

At one time, most capacitor banks were housed in metal enclosures. While this provided superior appearance and a certain margin of safety over exposed equipment, it was expensive, the size and voltage was limited and there were ventilating problems. Furthermore, expulsion fuses could not be used and large equipment bushings were necessary. Today, housed capacitor equipment is seldom ordered for substations. However, where appearance is a matter of special concern, capacitor manufacturers offer cosmetic versions of their standard equipment. The future may see significant reductions in capacitor bank overall sizes as the potential of SF_6 gas to reduce clearances for indoor housed equipment is fully exploited.

8. Tests

In the United States, shunt power capacitors are usually tested in accordance with ANSI C55.1 Part 6. There are two types of tests; i.e., production tests and design tests.

9. Typical Technical Specification

a. Type and Rating

This specification covers (1) ______ kVAR, ______ kV, 60 Hz, 3 phase outdoor (open rack) (housed) shunt capacitor bank, connected (wye) (delta) (grounded wye) (double wye). The manufacturer shall guarantee in writing that the capacitor bank meets the requirements of ANSI C55.1, NEMA CP-1, and other applicable American Standards in all respects.

The capacitor units shall be mounted in (upright) (edgemount) racks that shall be (fully equipped) (partly equipped and arranged for a maximum of ______ units each).

______ banks of capacitors, each rated ______ kVAR will ultimately operate in parallel on the same bus (and will be separately switched). The banks will be separated by approximately ______ feet of bus, anticipated to have a maximum inductance of ______ microhenry. The manufacturer shall make suitable provision to limit the inrush currents due to back-to-back capacitor switching to the capabilities of the switches and fuses. A bus reactor would be the user's responsibility.

All energized line parts shall be at least eight feet above the ground.

b. Controls

The capacitor bank shall (not) be equipped with a neutral protective control.

The capacitor bank shall be equipped with a (voltage) (current) (VAR) (current compensated voltage) (time) (temperature) (other ______) control.
(Cross out if not applicable)

The secondary control voltage available at the substation will be ______ volts, (60 Hz) (dc).

c. Switching Devices

The capacitor bank shall be furnished with the following switching devices:

______ ground switch(es)
______ shorting switches
______ disconnect switches
______ power switching device

d. Elevating Substructure(s)

The manufacturer shall (not) furnish substructures that will elevate the capacitor racks a minimum of (2.44) (_____) meters ((8) (_____) feet) above the ground.

e. Accessories

Base and stack insulators shall be high strength (cap and pin) (station post) and shall be colored (ANSI #70 gray) (brown).

The manufacturer shall furnish all necessary racks, shelves, superstructures, bus work, insulators, connections, terminals and hardware. If aluminum connections are involved, a container of oxide inhibitor shall be furnished. A can of touch-up paint of the same color as the capacitors shall be furnished.

Any necessary instrument transformers for proper operation of the controls shall be furnished. They shall be suitably protected by means of arresters, protector tubes or gaps, as required.

f. Drawings and Instruction Books

The manufacturer shall supply suitable drawings (for approval) (for installation) (for record) as follows:

Outline
Auxiliary equipment outlines
Bills of major material
Hardware schedule
Base plan
Interconnection diagram

The manufacturer shall also furnish ______ copies of pertinent

Instruction books
Spare parts lists

Maintenance manuals
Fuse curves (min. melt and maximum total clearing)
Capacitor case bursting curves

The manufacturer shall furnish the information specified on the attached data sheet.

g. <u>Information to be Furnished With Proposal</u>

Each proposal submitted to furnish the capacitor banks covered by this specification shall include, in addition to the quoted price and promised delivery, the following information in the form and sequence indicated:

(1) Rated voltage of individual capacitors, v _____

(2) Rated capacity of individual capacitors, kVAR _____

(3) BIL, kV _____

(4) Case material _____

(5) Rack material _____

(6) Bus material _____

(7) Dimensions (furnish sketch)

(8) Weights (furnish)

(9) Volts per internal pack or section at rated voltage _____

(10) Number of sheets of dielectric between foils _____

(11) Total nominal dielectric thickness (in mils) between foils _____

(12) Working voltage stress-maximun (9) ÷ (11) _____

*(13) Temperature rise of isolated capacitor unit at rated voltage and kVAR in 40°C still air

(a) Internal hot spot _____

(b) Case hot spot _____

*(14) Temperature rise of the maximum loss unit while operating at 110 percent rated voltage indoors between two others in 46°C still air ambient

(a) Internal hot spot ______

(b) Case hot spot ______

Note: Items are to be considered guarantees and subject to verification by tests on comparable units produced at the same time as units to be furnished in accordance with this specification. Purchaser reserves option to visit factory to witness dielectric hot spot temperature test to establish that units will meet guaranteed temperatures.

* Isolated unit per Paragraph 3.03 of NEMA CP-1

** Conditions per Paragraph 5.04, Part B of NEMA CP-1

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13. "An Appraisal of Tests and Standards for the Evaluation of Electrical Insulating Fluids," U.S. Department of Commerce, National Technical Information Service, PB-253 110 (ERDA) 14 May 1976.

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15. "Guidelines for Handling and Disposal of Capacitor and Transformer Grade Askerels Containing Polychlorinated Biphenyls," Publication C107.1; American Materials Standards Institute, 1430 Broadway, New York, NY 10018.

16. "IEEE Guide for Acceptance and Maintenance of Transformer Askerel in Equipment," IEEE Standard 76, Published by IEEE, 345 East 47th Street, New York, NY 10017.

17. "Technical Data - A Reference for the Electrical Power Industry," Anderson Electric Corporation, Box 455, Leeds, Alabama 35094, p 164.

18. "Capacitor Case Rupture Withstand Capability and Fuse Protection Considerations," by R. A. Pratt, W. W. Olive, Jr., B. D. Whitman and R. W. Brown, presented to Edison Electric Institute, Transmission and Distribution Subcommittee, May 5-6, 1977.

19. "Guide for the Protection of Shunt Capacitor Banks," IEEE Proposed Standard-569/D6, April 1977.

APPENDIX

TO

SHUNT CAPACITOR EQUIPMENT

EXHIBIT I

Typical Inrush Current Calculations

(2) Capacitor Banks, each 13,500 kVAR, 14,400 volt, 60 Hz both switched by 15 kV vacuum switches, rated for 20,000 amp momentary peak,

$$L_T = \frac{MVAR \cdot 10^6 \cdot (n-1)}{(kA)^2 \cdot \pi \cdot f \cdot n}$$

Where,

L_T = Required inductance, μh

MVAR = Megavars per phase at 60 Hz

n = Number of parallel banks

f = Frequency, Hz

kA = Maximum allowable inrush current, kA

Here,

MVAR = 13.5/3 = 4.5

n = 2

kA = 20

f = 60

$$L_T = \frac{4.5\ (10^6)\ (2-1)}{(20)^2\ \pi\ (60)\ (2)} = 29.8\ \mu h$$

$$I = \frac{KVAR}{kV(3)^{\frac{1}{2}}} = \frac{4.5\ (3)}{14.4(3)^{\frac{1}{2}}} \times 1000 = 541 \text{ amp}$$

For this case, the equipment engineer would probably specify a 30 μh, 600 amp reactor in each phase of each bank.

EXHIBIT II

Inductive Reactance Between
Back-to-Back Capacitor Banks

$X_L = X_a + K_L$

Where,

X_L = Inductive reactance of bus, ohms/mile

X_a = Inductive reactance for 1 ft. spacing, ohm/mile

K_L = Spacing factor, ohms/mile

If the bus consists of 1 inch standard pipe size aluminum, spaced 8.2 feet apart and 90 ft. long:

Go to Table 77 on page 69 of Ref. 18 and interpolate, thus:

ft	K_L
9.0	0.2666
8.2	K_L
8.0	0.2523

$$\frac{0.2}{1.0} = \frac{K_L - 0.2523}{0.0143}$$

K_L = 0.2552 ohms/mile

$$X_a = 0.0682 \ \frac{\text{ohms}}{1000 \text{ ft}} \times \frac{5280}{1000} \ \frac{(1000) \text{ ft}}{\text{mile}}$$

$$= 0.3601 \text{ ohms/mile}$$

$$X_L = 0.3601 + 0.2552 = 0.6153 \text{ ohms/mile}$$

$$X_L \text{ total} = X_L \times \text{miles} = 0.6153 \times 90 \times \frac{1}{5280} = 0.105 \text{ ohms}$$

$$L = \underline{X} \qquad W = 2\pi f = 2\pi(60) = 377 \text{ rad/sec}$$

$$L = \frac{0.0105}{377} \times 106 = 27.8 \text{ mHs.}$$

Thus, the bus alone provides close to 30 mHs. of inductance for this configuration.

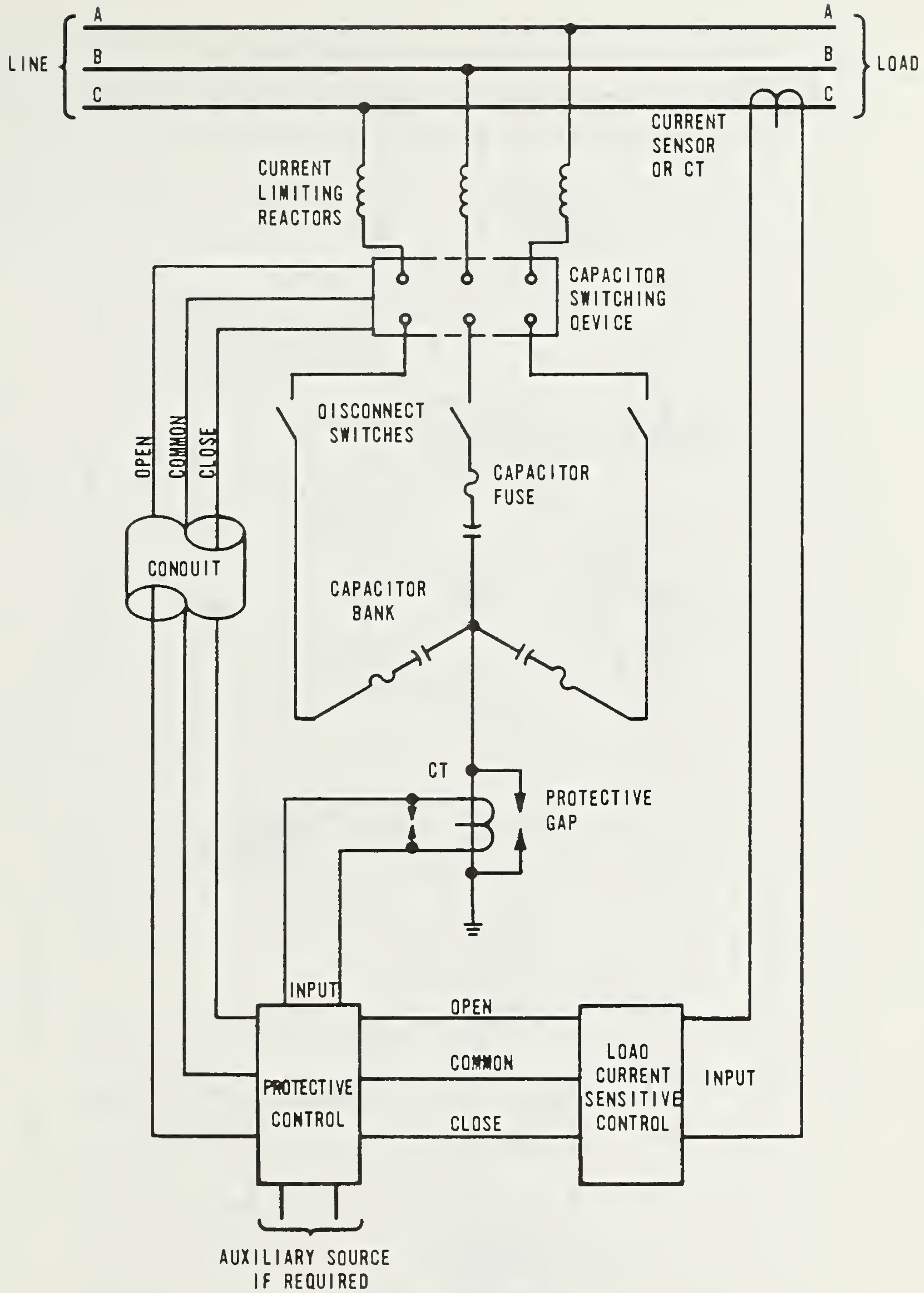


FIGURE V-2
TYPICAL CAPACITOR BANK GRD WYE CONNECTED

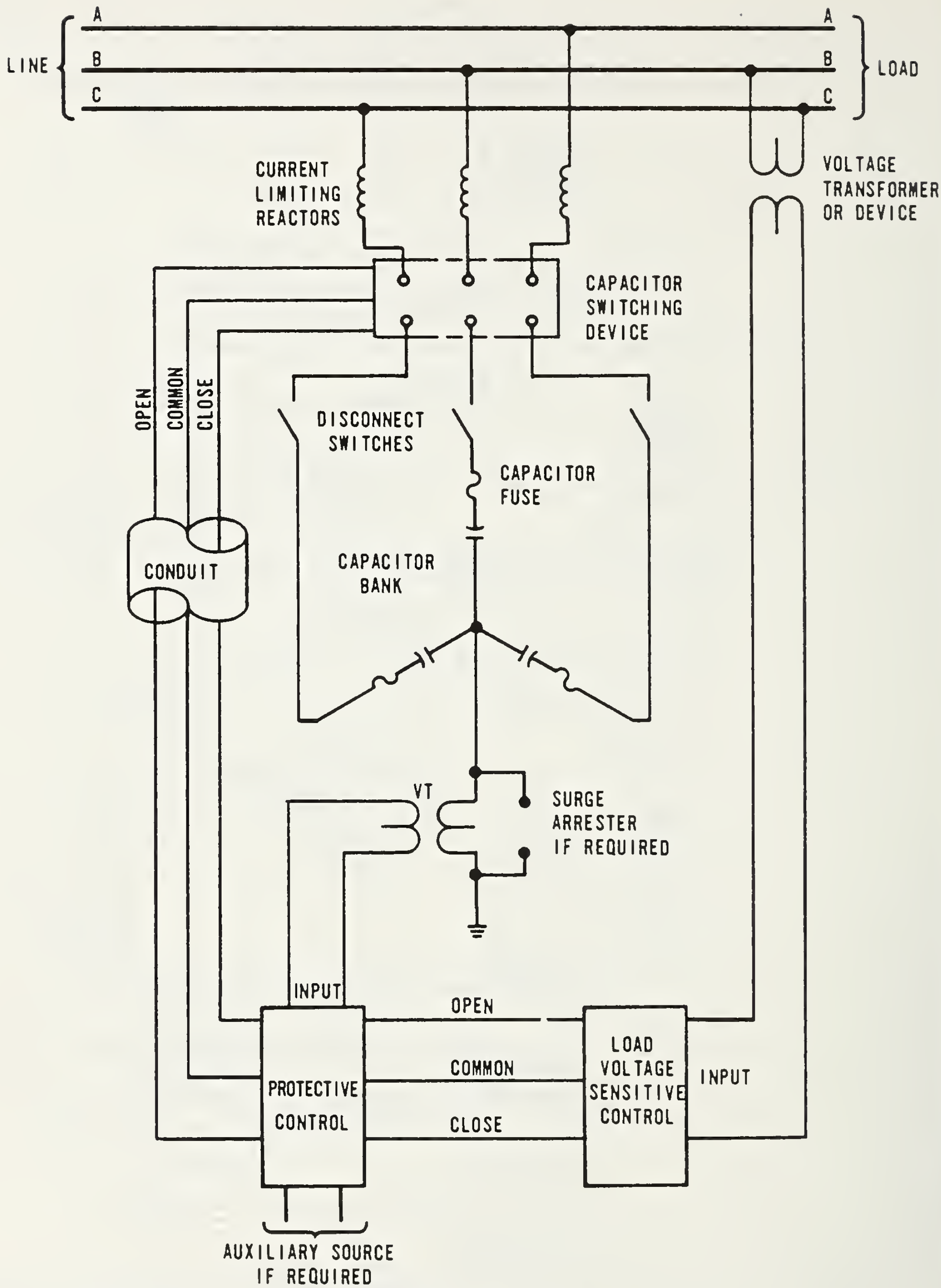


FIGURE V-3
TYPICAL CAPACITOR BANK FLOATING WYE

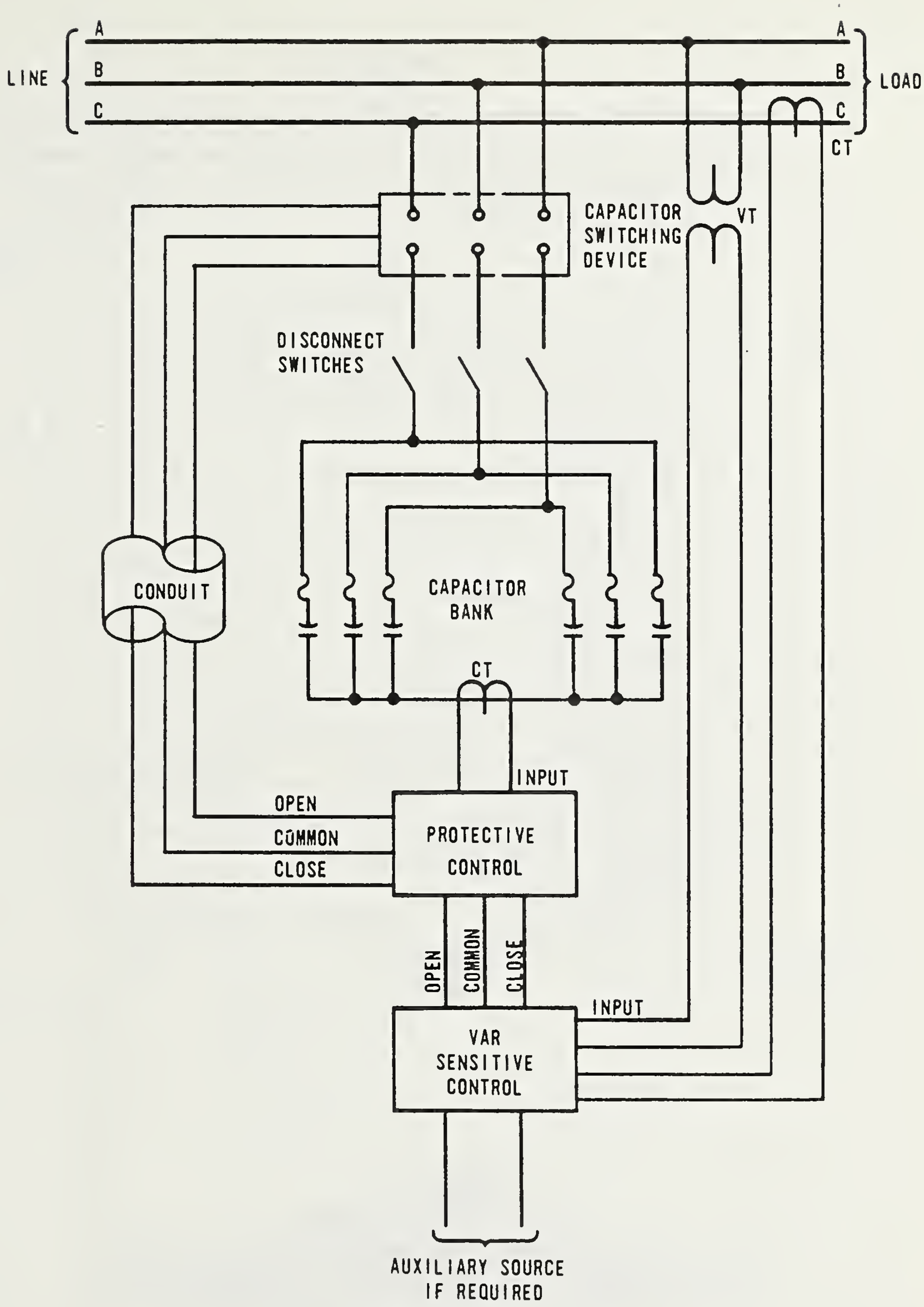


FIGURE V-4
TYPICAL CAPACITOR BANK WYE WYE CONNECTED

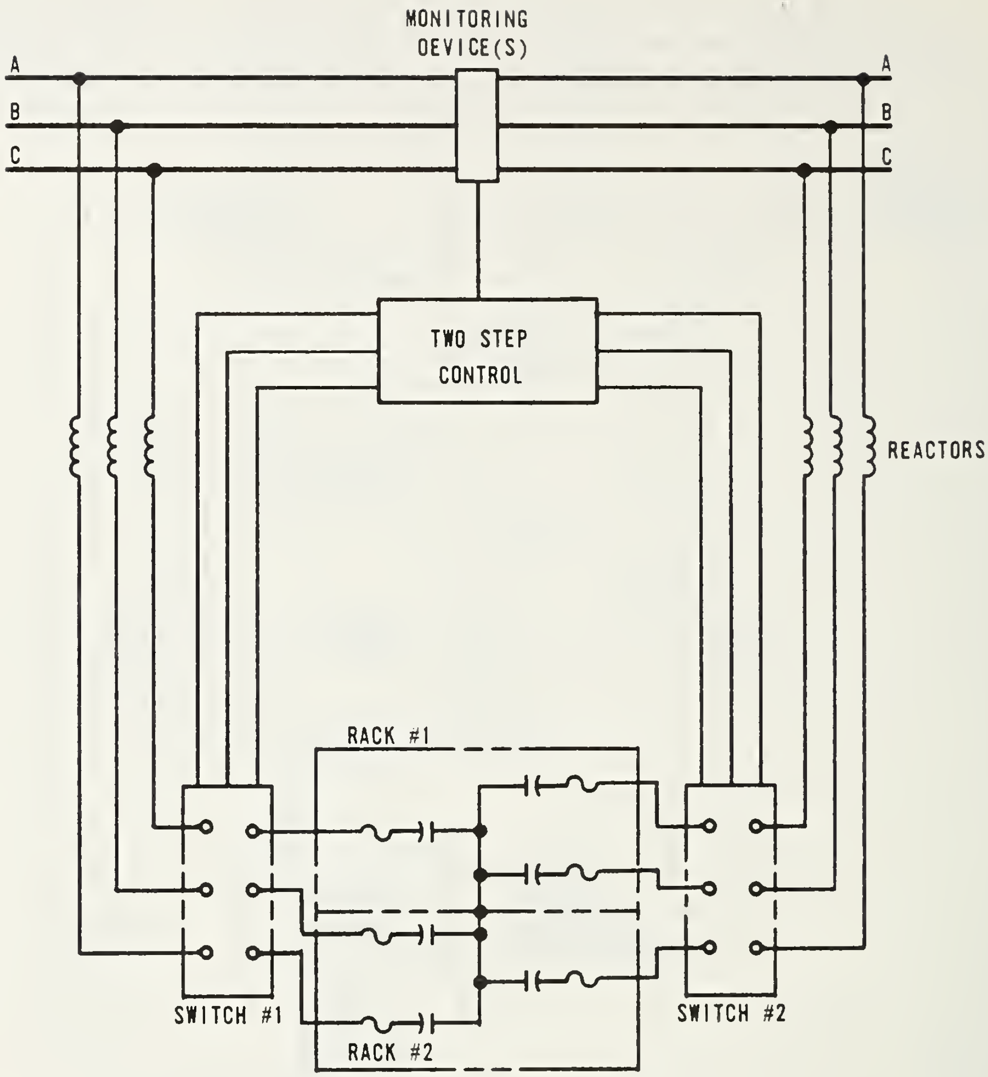


FIGURE V-5

TYPICAL CAPACITOR BANK

TWO THREE-PHASE CAPACITOR RACKS CONNECTED TO FORM A TWO-STEP BANK. FLOATING WYE WITH A COMMON NEUTRAL

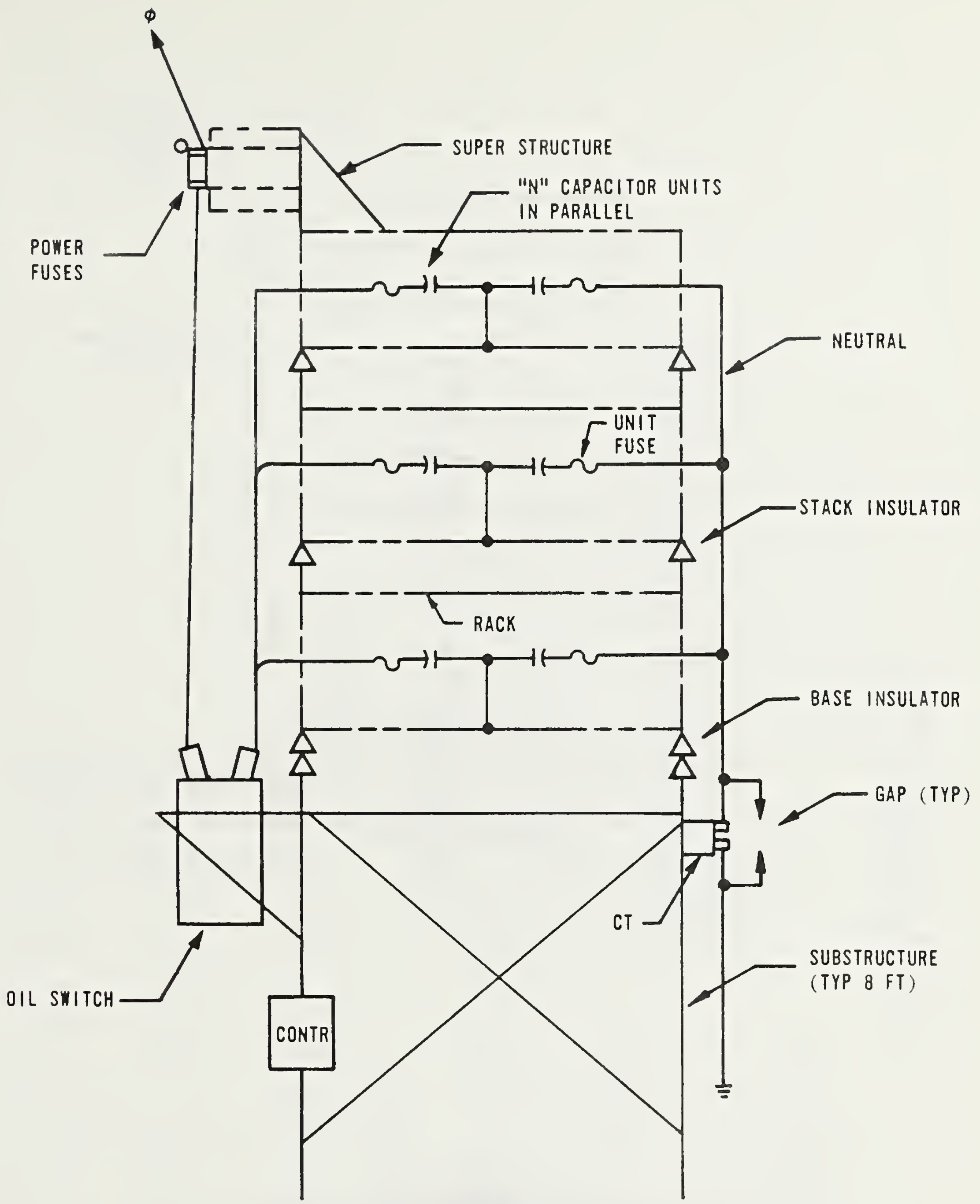


FIGURE V-6
A COMPLETE TYPICAL CAPACITOR EQUIPMENT
CONNECTED GRD WYE WITH 2 SERIES SECTIONS/
PHASE IN A SINGLE STACK

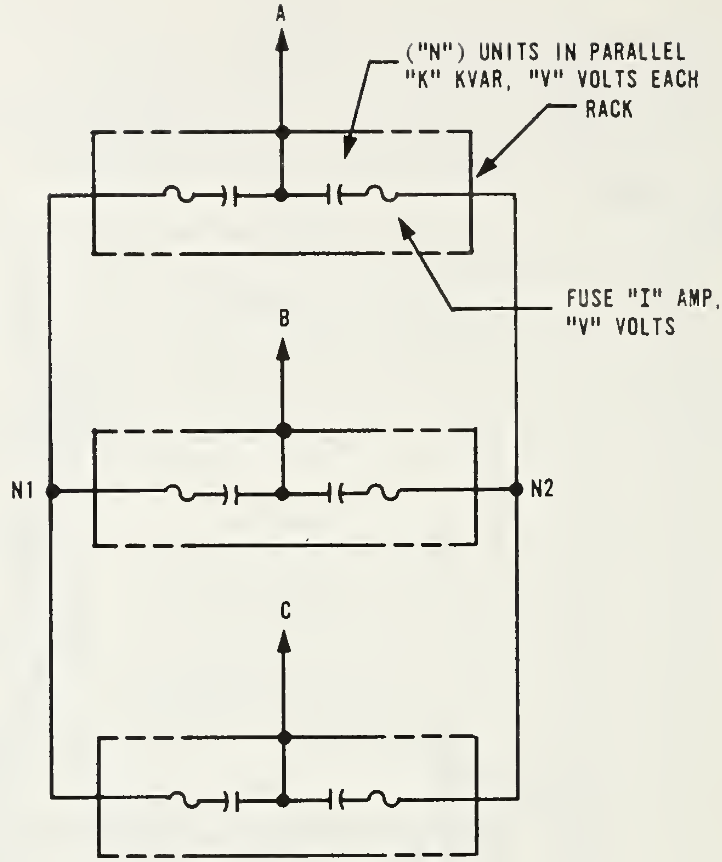


FIGURE V-7
A Y-Y CONNECTED CAPACITOR BANK
WITH ONE SERIES SECTION PER PHASE
AND NEUTRALS ISOLATED

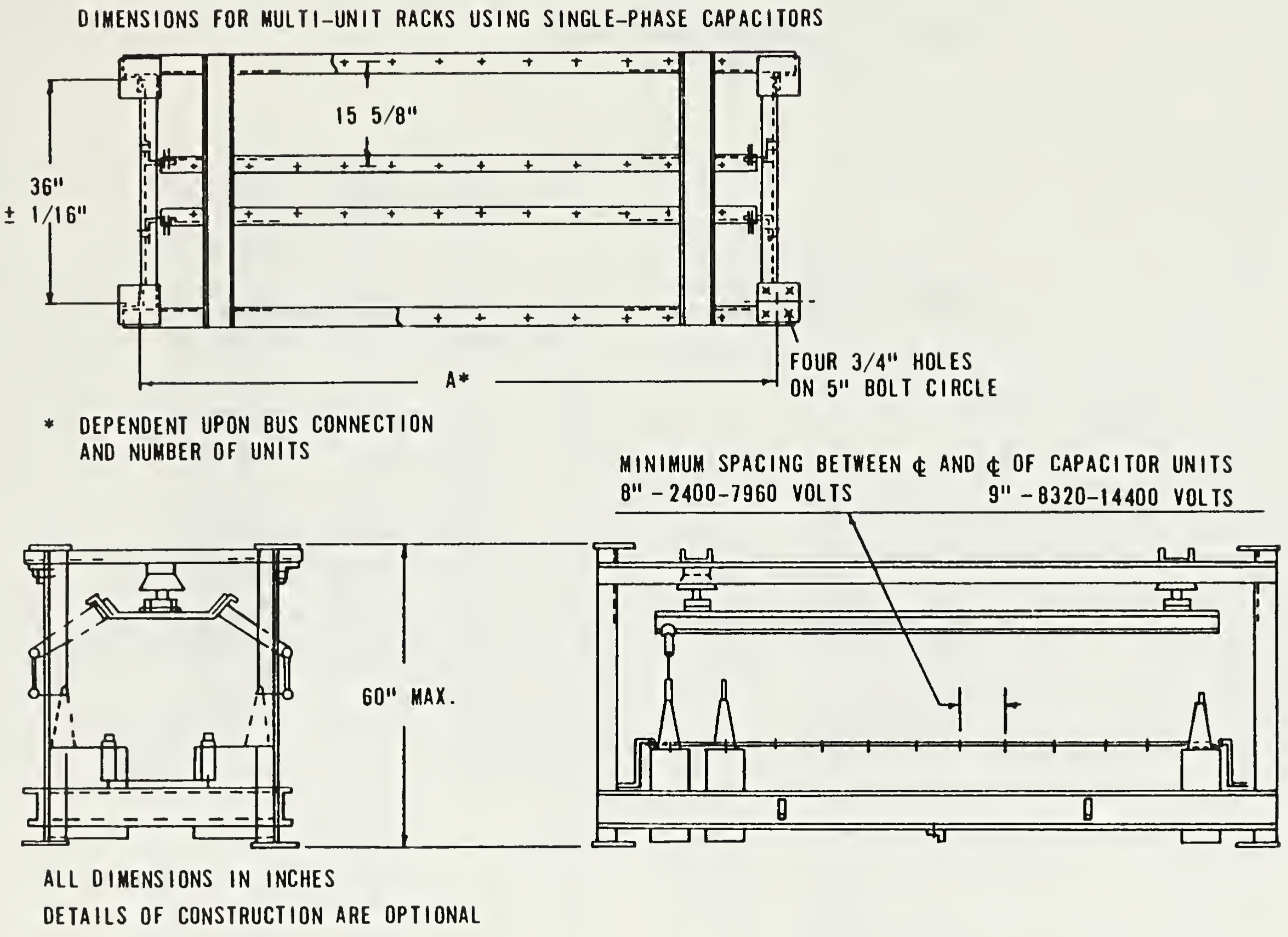


FIGURE 4-1
CAPACITORS VERTICALLY MOUNTED

REF. NEMA CP-1

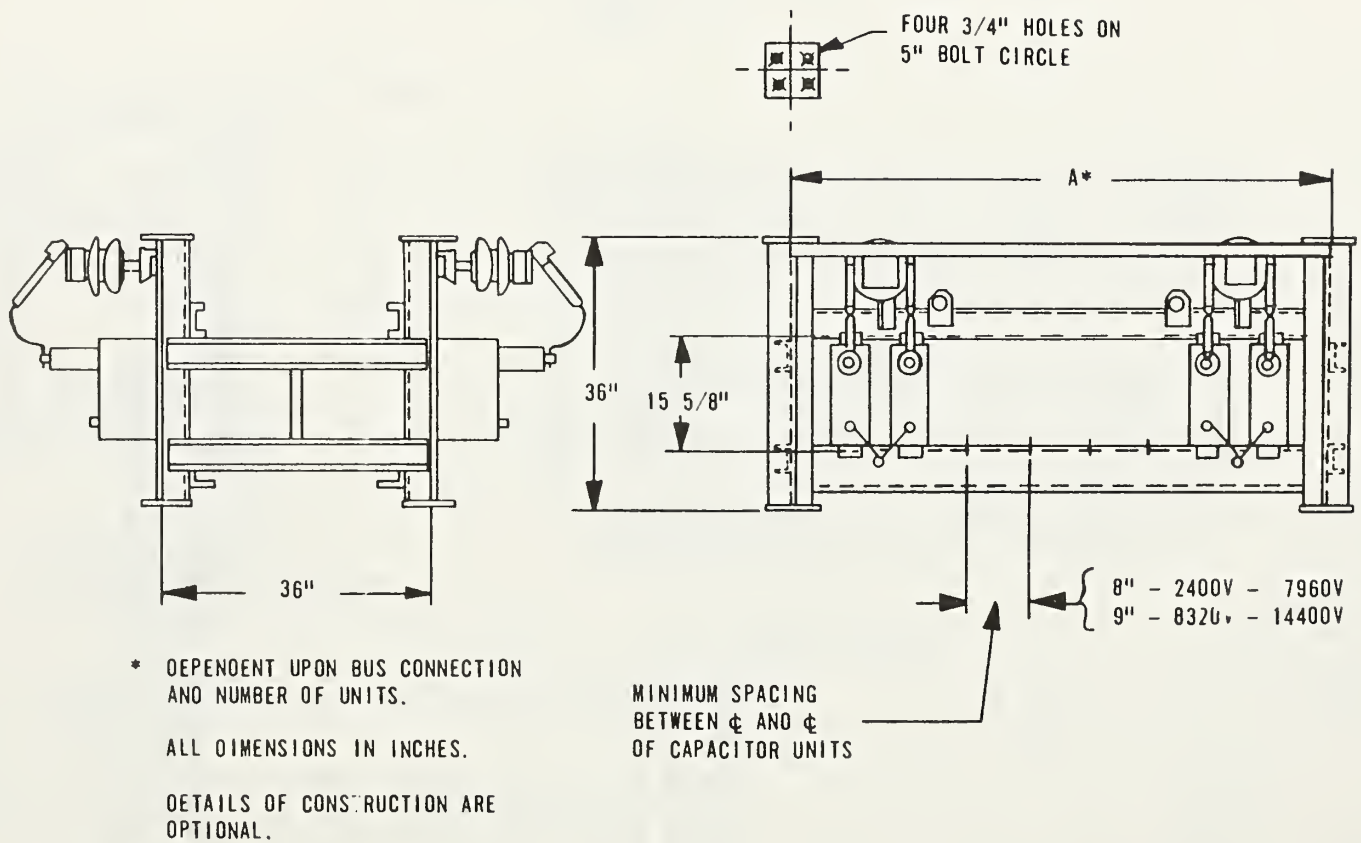


FIGURE 4-2
CAPACITORS HORIZONTALLY MOUNTED

REF. NEMA CP-1

G. AIR SWITCHES

1. General

This section deals with high-voltage air switches used in substations. Items discussed include: applicable national standards, types of air switches, various constructions of outdoor air switches, service conditions, ratings and tests.

The general function of an air switch is obtained from its ANSI (C37.30) Definition, "A switching device designed to close and open one or more electrical circuits by means of guided separable contacts that separate in air." Air, at atmospheric pressure, is also the insulating medium between contacts in the open position.

Many varieties of air switches have been developed to fulfill special requirements of the user. The List of Materials, REA Bulletin 43-5, contains both fully accepted and conditionally accepted types of air switches and should be consulted whenever air switches are required. When applying air break switches, the user should also review the information provided in REA Bulletin 60-3, "Load Interrupting Capabilities of Outdoor Air Switches."

All varieties of air switches used in REA Borrower's Substations shall, in general, conform to all applicable national standards and guides. The main standards and guides for air switches are:

ANSI C37.30, "Definitions and Requirements for High-Voltage Air Switches, Insulators and Bus Supports"

ANSI C37.31, "Electrical and Mechanical Characteristics of Indoor Apparatus Insulators"

ANSI C37.32, "Schedules of Preferred Ratings, Manufacturing Specifications and Application Guide for High-Voltage Air Switches, Bus Supports and Switch Accessories"

ANSI C37.33, "Rated Control Voltages and Their Ranges for High-Voltage Air Switches"

ANSI C37.34, "Test Code for High-Voltage Air Switches"

ANSI C37.35, "Guide for the Operation and Maintenance of High-Voltage Disconnecting Switches"

ANSI C29.1, "Test Methods for Electrical Power Insulators"

ANSI C29.8, "Wet-Process Porcelain Insulators (Apparatus, Cap and Pin Type)"

ANSI C29.9, "Wet-Process Porcelain Insulators (Apparatus, Post Type)"

NEMA Publication SG-6, "Power Switching Equipment"

2. Types of Air Switches

The main types of air switches are determined by and named according to their application. Standard definitions, according to ANSI C37.30, describe their general function:

a. Disconnecting or Isolating Switch (Disconnector, Isolator)

"A mechanical switching device used for changing the connections in a circuit, or for isolating a circuit or equipment from the source of power." This switch is required to carry normal load current continuously and, also, abnormal or short-circuit currents for short intervals as specified. It is also required to open or close circuits either when negligible current is broken or made, or when no significant change in the voltage across the terminals of each of the switch poles occurs.

Typical Applications:

Circuit Breaker Isolation
Power Transformer Isolation
Voltage Transformer Disconnecting
Equipment Bypassing
Bus Sectionalizing

Note: Where the current to be broken or made is not negligible, a Horn-Gap Switch, (see Paragraph 2.c,) should be used.

b. Grounding Switch

"A mechanical switching device by means of which a circuit or piece of apparatus may be electrically connected to ground." Grounding switches are often mounted on the jaw or hinge end of disconnecting or horn-gap switches.

Typical Applications

To ground buses or circuits (for safe maintenance) after they are first isolated.

To intentionally ground a circuit (using an automatic high speed device) in order to activate a remote protective relaying scheme.

c. Horn-Gap Switch

"A switch provided with arcing horns."

Typical Application:

To de-energize or energize a circuit that possesses some limited amount of magnetic or capacitive energy, such as transformer exciting current or line charging current. The arcing horns protect the main contacts during opening or closing and enhance the ability of the switch to perform its task.

Note: Where the amount of current to be broken or made is not clearly within the switch's capability, the manufacturer should be consulted or an Interrupter Switch, see Paragraph 2.d, should be used.

d. Interrupter Switch

"An air switch, equipped with an interrupter, for making or breaking specified currents, or both." The nature of the current made or broken, or both may be indicated by a suitable prefix, i.e., load interrupter switch, fault interrupter switch, capacitor current interrupter switch, etc. Typical applications are indicated by the above name prefixes.

e. Selector Switch

"One arranged to permit connecting a conductor to any one of a number of other conductors." In substation applications, it is unlikely that more than two conductors would be subject to selection.

Typical Applications:

To connect a potential device to either of two buses.

To perform a joint disconnecting and grounding function.

3. Various Constructions of Outdoor Air Switches

Outdoor air switches are constructed in many different styles or construction classifications. Preferred standard ratings depend on the construction classification. A pictorial representation of each classification is shown at the bottom of Table 1 (see Appendix) of ANSI C37.32. The various constructions are listed below and described, including ANSI C37.30 definitions (in quotations) where appropriate.

a. Vertical Break Switch (Construction Classification A)

"One in which the travel of the blade is in a plane perpendicular to the plane of the mounting base. The blade in the closed position is parallel to the mounting base." The hinge end includes two insulators, one of which is caused to rotate by the operating mechanism and thereby open and close the blade.

b. Double Break Switch (Construction Classification B)

"One that opens a conductor of a circuit at two points." The center insulator stack rotates to accomplish the opening and closing operation.

c. Tilting-Insulator Switch (Construction Classifications C & F)

"One in which the opening and closing travel of the blade is accomplished by a tilting movement of one or more of the insulators supporting the conducting parts of the switch."

d. Side-Break Switch (Construction Classification D)

"One in which the travel of the blade is in a plane parallel to the base of the switch." The hinge end insulator rotates to accomplish the opening and closing operation.

e. Center-Break Switch (Construction Classification E)

One in which travel of the blade is in a plane parallel to the base of the switch and that opens in the center at only one point. Both insulators rotate to accomplish the opening and closing operation.

f. Grounding Switch (Construction Classification G)

ANSI definition is in Paragraph 2.b. The pictorial representation in Table 1 (see Appendix) of ANSI C37.32 shows a type where an insulated blade, connected to a bus or a piece of equipment, is made to contact ground. Some types use a normally grounded blade, which is made to contact the bus or equipment to be grounded.

g. Hook Stick Switch (Construction Classification H)

One that is opened manually by means of a switch stick. Both insulators remain stationary when the blade, hinged at one end, is unlatched and opened or closed by the switch stick. These are single- pole (1 phase) switches.

h. Vertical Reach Switch (Construction Classification J)

One in which the stationary contact is supported by a structure separate from the hinge mounting base. The blade in the closed position is perpendicular to the hinge mounting base.

4. Usual Service Conditions

The ratings of all high-voltage air switches covered by the standards are based on:

a. Temperature

Ambient temperature of cooling air over the switch is within the range of -30°C to +40°C for nonenclosed

indoor or outdoor switches. Ambient temperature of cooling air over the switch does not exceed 55°C for enclosed indoor or outdoor switches. Maximum ambient outside the enclosure does not exceed 40°C.

b. Altitude

Altitude does not exceed 1000 meters (3300 feet). Correction factors should be applied above 1000 meters as shown in Table 1 (see Appendix) of ANSI C37.30.

5. Ratings

a. General

The various ratings covered by the ANSI Standards for the several types of air break switches are indicated by an "X" in Table 2 (see Appendix) of ANSI C37.30. All these ratings are defined in C37.30, Section 4; however, the main rating definitions applicable to "disconnecting switches" will be repeated here for convenience, since this is the most common air switch used in substations. For the most part, the ratings repeated here also apply to the other switch types.

b. Disconnecting Switch Ratings

(1) Rated Voltage is the highest nominal system voltage on which it is intended to be applied.

(2) Rated Maximum Voltage is the highest rms voltage at which the device is designed to operate.

(3) Rated Continuous Current is the maximum direct current, or rms alternating current, in amperes, at rated frequency that it will carry continuously without exceeding the limit of observable temperature rise.

Note: Allowable Continuous Current at a specific ambient temperature is the maximum direct current, or rms alternating current, in amperes, at rated frequency that it will carry without exceeding the allowable temperature for any of its parts as listed in Column 1 of Table 3 (see Appendix) of ANSI C37.30.

The allowable continuous current may be determined from the equation:

$$I_A = I_R \left(\frac{\theta max - \theta_A}{\theta_r}\right)^{\frac{1}{2}}$$

where:

θ_A = ambient temperature (°C)

I_A = allowable continuous current at θ_A

I_R = rated continuous current

θmax = allowable temperature of switch part from Table 3

θ_r = Limit of observable temperature rise (°C) at rated current of switch part from Table 3.

The values of θ_r in Table 3 have been selected (when the switch is tested in accordance with Section 4 of ANSI C37.34) to maintain a loadability of 1.22 at 25°C, (77°F) where:

Loadability of a non-enclosed air switch is the ratio of allowable continuous current at 25°C (77°F) ambient temperature to rated current. The Loadability of an enclosed air switch is the ratio of allowable continuous current at 40°C (104°F) inside ambient temperature to rated current.

Users in colder climates and those with maximum load currents, known to occur during ambients lower than 40°C (104°F), should carefully consider the possible cost benefits from taking advantage of allowable continuous currents when selecting the continuous current rating of any air break switch. In such applications, a lower continuous current rating may be sufficient, compared to a rating based strictly on the maximum direct, or rms alternating current, of the circuit in question.

(4) Rated Short Time Current (Momentary and Three-Second)

(a) Rated Momentary Current is the rms total current that the switch shall be required to carry for at least one cycle. The current shall be the rms value, including the direct current component, during the maximum cycle as determined from the envelope of the current wave, and the test period shall be at least ten cycles.

(b) Rated Three-Second Current is the rms total current, including any direct current component, which the switch shall be required to carry for three seconds.

(5) Rated Withstand Voltage shall be the voltage that the device must withstand without flashover or other electric failure when voltage is applied under specified conditions. The standard low-frequency wet and dry and 1.2 x 50 microsecond impulse withstand voltages are listed in ANSI C37.32.

(6) The preferred ratings of voltage, continuous current, short-time current ratings, dielectric withstand voltages and radio influence test voltages of various constructions of outdoor air switches (at 60 Hz) shall be in accordance with Table 1 (see Appendix) of ANSI C37.32.

6. Other Requirements

a. Insulators used shall have sufficient strength to withstand the magnetic forces produced by the rated momentary current ratings specified in Table 1 of ANSI C37.32.

b. The arrangement and size of bolt holes in terminal pads, when used, shall be in accordance with Table 2 (see Appendix) of ANSI C37.32.

c. The length of break of outdoor air switches, when in the fully open position, shall be at least 10 percent in excess of the dry arcing distance over the insulators and shall be such that the open gap(s) will withstand a test voltage is 10 percent in excess of

the low-frequency dry and impulse withstand test voltage given in Table 1 of ANSI C37.32.

d. The minimum metal-to-metal single-pole break distances and the single-pole centerline-to-centerline spacings of insulator columns shall be as specified in Table 3 (see Appendix) of ANSI C37.32.

e. Base mounting holes for outdoor air switches shall be as specified in Table 4 (see Appendix) of ANSI C37.32.

f. Phase spacing (pole spacing), centerline-to-centerline, for outdoor air switches shall be as specified in Table 5 (see Appendix) of ANSI C37.32.

g. Preferred ratings and other requirements for indoor air switches, grounding switches, fault initiating switches and load interrupter switches are listed in ANSI C37.32, Sections 3 through 6, respectively.

7. Mounting Considerations

a. Air switches should be mounted on supports strong enough to ensure that current carrying contacts mate properly when opened and closed, since considerable reaction forces are exerted on the supports during operation.

b. Whenever possible, air switches should be oriented so that the blade is dead when the switch is open.

c. The intended mounting arrangement of air break switches should be made known to the manufacturer so that the insulators will be properly assembled.

APPENDIX

TO

AIR SWITCHES

Table 1
Altitude Correction Factors

Altitude Feet	Altitude Meters	Altitude Correction Factor To Be Applied to: Rated Withstand Voltage Col 1	Current Rating * Col 2	Ambient Temperature † Col 3
3300	1000	1.00	1.00	1.00
4000	1200	0.98	0.995	0.992
5000	1500	0.95	0.99	0.980
6000	1800	0.92	0.985	0.968
7000	2100	0.89	0.98	0.956
8000	2400	0.86	0.97	0.944
9000	2700	0.83	0.965	0.932
10 000	3000	0.80	0.96	0.920
12 000	3600	0.75	0.95	0.896
14 000	4200	0.70	0.935	0.872
16 000	4800	0.65	0.925	0.848
18 000	5400	0.61	0.91	0.824
20 000	6000	0.56	0.90	0.800

* For maximum ambient of 40°C for nonenclosed switches and 40°C outside the enclosure for enclosed switches.

† For operation at continuous current rating.

Ref. C37.30

Table 2
Switch Ratings

	Disconnecting Switch	Load Interrupter Switch	Interrupter Switch with Capacitance Ratings	Fault Initiating Switch	Grounding Switch
	Col 1	Col 2	Col 3	Col 4	Col 5
Rated voltage	X	X	X	X	X
Rated maximum voltage	X	X	X	X	X
Rated frequency	X	X	X	X	X
Rated continuous current	X	X	X	—	—
Rated short-time current (Momentary and three-second)	X	X	X	—	X
Rated interrupting current	—	X	—	—	—
Rated switching current — single capacitance	—	—	X	—	—
Rated switching current — parallel-connected capacitance	—	—	X	—	—
Operating life expectancy	—	*	X	*	—
Rated withstand voltage	X	X	X	X	X
Rated making current	—	—	—	X	—
Rated closing time	—	—	—	X	—
Rated differential capacitance voltage					
Maximum	—	—	X	—	—
Minimum	—	—	X	—	—
Rated capacitance switching transient overvoltage ratio	—	—	X	—	—

* Consult the manufacturer.

Ref. C37.30

Table 3
Temperature Limitations for Air Switches

Switch Part	Allowable Max Temperature, θ max	Limit of Observable Temperature Rise at Rated Current (θ_r) (°C): Nonenclosed Indoor and Outdoor Switches (see Note 1)	Limit of Observable Temperature Rise at Rated Current (θ_r) (°C): Enclosed Indoor and Outdoor Switches
	Col 1	Col 2	Col 3
(1) Contacts in air (see Note 2)			
(a) Copper or copper alloy	75	33	20
(b) Copper or copper alloy to silver or silver alloy, or equivalent	90	43	33
(c) Silver, silver alloy, or equivalent	105	53	43
(d) Other (see Note 3)	—	—	—
(2) Conducting mechanical joints			
(a) Copper or aluminum	90	43	33
(b) Silver, silver alloy, or equivalent	105	53	43
(c) Other (see Note 3)	—	—	—
(3) Switch terminals with bolted connections	90	43	33
(4) Welded or brazed joints or equivalent	105	53	43
(5) Other current-carrying parts			
(a) Copper or copper alloy castings	105	53	43
(b) Hard drawn copper parts (see Note 4)	80	37	25
(c) Heat treated aluminum alloy parts	105	53	43
(d) Woven wire flexible connectors	75	33	20
(e) Other materials (see Note 3)	—	—	—
(6) Insulator caps and pins and bushing caps	110	57	47
(7) Current-carrying parts in contact with insulating materials (see Note 5)			
(a) Insulation Class 90°C	80	37	25
(b) Insulation Class 105°C	95	47	37
(c) Insulation Class 130°C	120	63	53
(d) Insulation Class 155°C	145	80	70
(e) Insulation Class 180°C	170	97	87
(f) Insulation Class 220°C	210	123	113
(g) Oil (see Note 6)	90	43	33
(8) Nonenergizable parts subjected to contact by personnel			
(a) Handled by operator (see Note 7)	50	10	10
(b) Accessible to operator (see Note 7)	70	30	30
(c) Not accessible to operator (see Note 8)	—	—	—

Ref. C37.30

NOTES to Table 3:

(1) The limit of observable temperature rise listed in this column is suitable for use in rating switches for application in enclosures of American National Standard C37.20-1969, if corresponding allowable maximum temperature listed in column 1 is not exceeded when in the enclosure.

(2) Contacts are used here include: (a) stationary and moving contacts that engage and disengage and (b) contacts that have relative movement but remain engaged.

(3) Other materials may become available for contacts and conducting mechanical joints and other current-carrying parts that have a different allowable maximum temperature, θ_{max}. Their limit of observable temperature rise at rated current, θ_r, shall be related to their θ_{max} in accordance with the following:

For nonenclosed switches, $\theta_r = \dfrac{\theta_{max} - \theta_a}{1.5}$

For enclosed switches, the lesser of:

(1) $\theta_r = \dfrac{\theta_{max} - \theta_{e1}}{1.5}$ or

(2) $\theta_r = \theta_{max} - \theta_{e2}$

where

$\theta_a = 25°C$

$\theta_{e_1} = 40°C$

$\theta_{e_2} = 55°C$

$1.5 = (1.22)^2$

where 1.22 is the loadability of the switch

(4) If annealing will not impair switch operation or reduce ability to meet any of the ratings, 105°C may be used for θ_{max} and corresponding increase in θ_r as determined by Section 4.13.

(5) The temperature of materials used to insulate the switch conducting parts from phase to ground, from phase to phase, or from terminal to terminal of an open switch shall be limited to the values listed. It is recognized that these limits are generally less than those associated with the insulating class in IEEE General Principles for Temperature Limits in the Rating of Electric Equipment, IEEE No. 1, April 1969, since such insulation may be subject to severe mechanical as well as dielectric stress when used on high-voltage switches. Although all insulation temperature classes are included for completeness, and to allow possible future use of higher temperature current-carrying material, maximum temperatures of current-carrying materials listed in Table 1 shall not be exceeded.

(6) The top oil (upper layer) temperature shall not exceed 80°C total. The 90°C value refers to the hottest-spot temperature of parts where they contact the oil.

(7) It is assumed that any parts handled by or accessible to an operator will be in ambient air not to exceed 40°C.

(8) The maximum temperature of any nonenergizable part not accessible to the operator shall not exceed a temperature which will necessitate maintenance or replacement of parts during the life of the switch.

Ref. C37.30

Table 1

Preferred Ratings for Outdoor Air Switches of Various Constructions

Line No.	Rated Max Voltage (kV rms)	Rated Withstand Voltage: Impulse 1.2 × 50 μs Wave kV Crest	Rated Withstand Voltage: 60 Hz kV rms, Wet 10 Seconds	Rated Withstand Voltage: 60 Hz kV rms, Dry 1 Minute	Main Switch Continuous Current Rating, Amperes, rms: 400; Momentary Asymmetrical Current Rating, Thousands of Amperes, rms*: 20	600; 40	1200; 40	1200; 61	1600; 70	2000; 70	2000; 100	3000; 70	3000; 100	3000; 120	4000; 120	Radio Influence Test Voltages and Limits‡: Test Voltage kV†	Radio Influence Test Voltages and Limits‡: Limit of Radio Influence Voltage (microvolts at 1 megahertz)
					Construction Classification												
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
1	8.25	95	30	35	ACDEFGH	ACDEFGH	–	ADGH	–	H	A	–	–	AH	AH	5.0	**
2	15.5	110	45	50	ACDEFGH	ACDEFGH	–	ADGH	–	H	A	–	–	AH	AH	9.4	**
3	25.8	150	60	70	ACDEFGH	ACDEFGH	–	ADGH	–	H	A	–	–	AH	AH	15.7	**
4	38.0	200	80	95	ABCDEFGH	ABCDEFGH	–	ABDEGH	–	H	A	–	–	AH	AH	23.0	**
5	48.3	250	100	120	–	ABDEGH	H	ABDEG	–	–	A	–	–	A	–	29.3	**
6	72.5	350	145	175	–	ABDEGH	H	ABDEG	ABEG	–	ABE	–	–	A	–	44.0	**
7	121	550	230	280	–	ABDEGH	DH	ABGE	ABEG	–	ABE	–	AB	–	–	73.4	**
8	145	650	275	335	–	ABDEGH	DH	ABEG	ABEG	–	ABE	–	AB	–	–	88.0	**
9	169	750	315	385	–	ABDEG	DH	ABEG	ABEG	–	ABE	–	AB	–	–	102.5	**
10	242 §	900	385	465	–	G	–	ABEG	ABEG	–	ABE	–	AB	–	–	147.0	**
11	242 §	1050	455	545	–	G	–	G	ABEG	AB	–	AB	–	–	–	147.0	**
12	362 §	1050	455	545	–	G	–	G	ABEG	AB	–	AB	–	–	–	220.0	**
13	362 §	1300	525	610	–	G	–	G	ABEG	ABJ	–	ABJ	–	–	–	220.0	**
14	550 §	1550	620	710	–	G	–	G	ABEG	ABJ	–	ABJ	–	–	–	340.0	**
15	550 §	1800	710	810	–	G	–	G	ABEG	ABJ	–	ABJ	–	–	–	340.0	**
16	765 §	2050	830	940	–	G	–	G	ABE	ABJ	–	ABJ	–	–	–	465.0	**

NOTE. Grounding switches have no continuous current ratings but have momentary and three-second ratings. Where grounding switches are applied to main switches, the momentary current ratings of the two are not necessarily the same.

*Short-time current ratings include a momentary and a three-second current rating based on test conditions described in Section 5 of American National Standard C37.34-1971. Divide the momentary rating by 1.6 to obtain the three-second current rating. When a higher momentary current rating than shown is required, use a switch having the next higher continuous current rating.

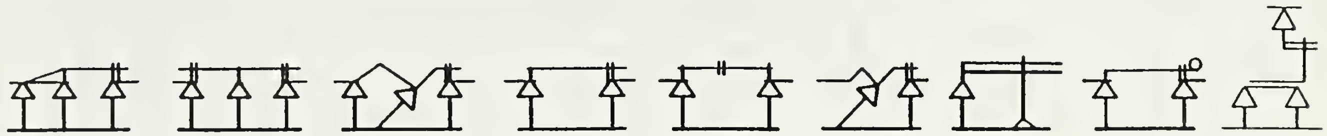
†The test voltages are 105 percent of the rated maximum line-to-neutral voltage.

‡See Section 3 of American National Standard C37.34-1971 for test procedure.

§The switches listed in lines 10 through 16 are intended for application on systems effectively grounded as defined in Neutral Grounding Devices, IEEE Publication No. 32, May 1947.

**RIV limits are under study pending development of American National Standards on methods of measurement of radio influence voltage on high-voltage apparatus.

††If equipment of any given rated maximum voltage is used on a circuit of a higher voltage rating, the radio influence voltage limit and test voltage for the equipment shall be that corresponding to its rated maximum voltage.



A Vertical — B Double — C Tilting — D Side — E Center — F Tilting — G Grounding — H Hook — J Vertical Reach

Ref. C37.32

Table 2
Arrangement and Size of Bolts in Terminal Pads

Continuous Current Rating (amperes)	Diameter of Bolts (inches)	Number of Bolts	Distance Center-to-Center Bolt Holes (inches)
400; 600	1/2 (12.7 mm)	2	1-3/4 (44.5 mm) parallel to centerline of switch
1200; 1600; 2000	1/2 (12.7 mm)	4	1-3/4 (44.5 mm) square

NOTE: Values not yet established for 3000 A and 4000 A switches.

Table 5
Outdoor Air Switches and Bus Supports
Phase Spacing

Line No.	Rated Maximum Voltage (kV rms)	Rated Withstand Voltage Impulse 1.2 X 50 µs Wave kV Crest	Minimum Metal-to-Metal Distance, All Disconnecting Switches, Bus Supports and Rigid Conductors (inches)	Centerline-to-Centerline Phase Spacing (inches): Vertical Break Disconnecting Switches and Bus Supports (inches)	Side Break (Horizontal Break) Disconnecting Switches (inches)	All Horn Gap Switches (Vertical and Side Break) (inches)
	(1)	(2)	(3)	(4)	(5)	(6)
1	8.25	95	7 (178 mm)	18 (0.457 m)	30 (0.762 m)	36 (0.914 m)
2	15.5	110	12 (304.8 mm)	24 (0.610 m)	30 (0.762 m)	36 (0.914 m)
3	25.8	150	15 (0.381 m)	30 (0.762 m)	36 (0.914 m)	48 (1.22 m)
4	38.0	200	18 (0.457 m)	36 (0.914 m)	48 (1.22 m)	60 (1.52 m)
5	48.3	250	21 (0.533 m)	48 (1.22 m)	60 (1.52 m)	72 (1.83 m)
6	72.5	350	31 (0.787 m)	60 (1.52 m)	72 (1.83 m)	84 (2.13 m)
7	121	550	53 (1.35 m)	84 (2.13 m)	108 (2.74 m)	120 (3.05 m)
8	145	650	63 (1.60 m)	96 (2.44 m)	132 (3.35 m)	144 (3.66 m)
9	169	750	72 (1.83 m)	108 (2.74 m)	156 (3.96 m)	168 (4.27 m)
10	242	900	89 (2.26 m)	132 (3.35 m)	192 (4.87 m)	192 (4.87 m)
11	242	1050	105 (2.67 m)	156 (3.96 m)	216 (5.50 m)	216 (5.50 m)
12	362	1050	105 (2.67 m)	156 (3.96 m)	216 (5.50 m)	216 (5.50 m)
13	362	1300	119 (3.02 m)	174 (4.43 m)	*	240 (6.10 m)
14	550	1550	*	*	*	*
15	550	1800	*	*	*	*
16	765	2050	*	*	*	*

NOTE: The phase spacings in Columns 4 and 5 are recommended values. It is recognized that at certain points of application these values may be reduced. Overall width of switch and bus support energized parts, angle of opening of side-break switches, etc. may allow a reduction in phase spacing. However, in no case should the resultant metal-to-metal distance between phase energized parts be less than that shown in Column 3.

Millimeter values approximate 25.4 mm per inch. Meter values approximate 0.0254 m per inch.

*Values are not yet established.

Ref. C37.32

Table 3
Outdoor Air Switches

Line No.	Rated Maximum Voltage (kV rms)	Rated Impulse Withstand Voltage 1.2 × 50 μs Wave kV Crest	Length of Break Minimum Metal-to-Metal: Single Break Distance (inches)*	Length of Break Minimum Metal-to-Metal: Double Break Distance (inches)*	Insulator Centerline-to-Centerline Spacing (inches minimum)*: Single Break Insulator Strength, Standard	Single Break Insulator Strength, High	Double Break Insulator Strength, Standard	Double Break Insulator Strength, High
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	8.25	95	7 (177.8 mm)	–	12 (304.8 mm)	15 (0.381 m)	–	–
2	15.5	110	10 (254.0 mm)	–	15 (0.381 m)	18 (0.457 m)	–	–
3	25.8	150	12 (304.8 mm)	–	18 (0.457 m)	21 (0.533 m)	–	–
4	38.0	200	18 (0.457 m)	12 (304.8 mm)	24 (0.610 m)	27 (0.686 m)	18 (0.457 m)	21 (0.533 m)
5	48.3	250	22 (0.559 m)	15 (0.381 m)	30 (0.762 m)	33 (0.838 m)	23 (0.585 m)	24 (0.610 m)
6	72.5	350	32 (0.813 m)	22 (0.559 m)	42 (1.07 m)	45 (1.14 m)	30 (0.762 m)	34 (0.864 m)
7	121	550	50 (1.27 m)	32 (0.813 m)	60 (1.52 m)	–	42 (1.07 m)	–
8	145	650	60 (1.52 m)	38 (0.965 m)	72 (1.83 m)	–	48 (1.22 m)	–
9	169	750	68 (1.73 m)	44 (1.12 m)	84 (2.13 m)	–	54 (1.37 m)	–
10	242	900	84 (2.13 m)	50 (1.27 m)	96 (2.44 m)	–	68 (1.73 m)	–
11	242	1050	104 (2.64 m)	57 (1.45 m)	114 (2.90 m)	–	75 (1.90 m)	–
12	362	1050	104 (2.64 m)	57 (1.45 m)	114 (2.90 m)	–	75 (1.90 m)	–
13	362	1300	120 (3.05 m)	66 (1.68 m)	132 (3.35 m)	–	84 (2.13 m)	–
14	550	1550	†	–	†	–	–	–
15	550	1800	†	–	†	–	–	–
16	765	2050	†	–	†	–	–	–

NOTE: Millimeter values approximate 25.4 mm per inch. See American National Standard Practice for Inch-Millimeter Conversion for Industrial Use, B48.1-1933 (R1947). Meter values approximate 0.0254 m per inch.

*The design of some switches may be such that the minimum metal-to-metal distance and the centerline-to-centerline spacing conflict. Where this occurs the minimum metal-to-metal distance should be used. Minimum metal-to-metal distances and resultant centerline-to-centerline spacing may be modified from the values listed above provided proof of performance is substantiated by the dielectric test in accordance with 2.4 of American National Standard C37.34-1971.

†Values are not yet established.

Ref. C37.32

Table 4
Outdoor Air Switches
Base Mounting Hole Spacing
400, 600, 1200, and 1600 Ampere Switches

Line No.	Rated Maximum Voltage (kV rms)	Hook Stick		Single Side Break		Vertical Break	
		A (inches)	B (inches)	A (inches)	B (inches)	A (inches)	B (inches)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	8.25	18 (0.457 m)	2 or 7 (50.8 mm or 178 mm)	24 (0.610 m)	3 or 7 (76.2 mm or 178 mm)	36 (0.914 m)	3 or 7 (76.2 mm or 178 mm)
2	15.5	21 (0.533 m)	2 or 7	24 (0.610 m)	3 or 7	36 (0.914 m)	3 or 7
3	25.8	24 (0.610 m)	2 or 7	24 (0.610 m)	3 or 7	39 (0.991 m)	3 or 7
4	38.0	30 (0.762 m)	2 or 7	33 (0.838 m)	3 or 8-1/4 (76.2 mm or 210 mm)	48 (1.22 m)	3 or 8-1/4 (76.2 mm or 210 mm)
5	48.3	39 (0.991 m)	3 or 8-1/4 (76.2 mm or 210 mm)	39 (0.991 m)	3 or 8-1/4	54 (1.37 m)	3 or 8-1/4
6	72.5	51 (1.29 m)	3 or 8-1/4	51 (1.29 m)	3 or 8-1/4	69 (1.75 m)	3 or 8-1/4
7	121	66 (1.68 m)	3 or 8-1/4	72 (1.83 m)	8-1/4	87 (2.21 m)	8-1/4
8	145	78 (1.98 m)	3 or 8-1/4	84 (2.13 m)	8-1/4	99 (2.51 m)	8-1/4
9	169	90 (2.29 m)	8-1/4	96 (2.44 m)	8-1/4	111 (2.82 m)	8-1/4

NOTE: "A" is the dimension along the length of the base and "B" is the dimension along the width of the base in inches.
Ratings for switches above 169 kV have not yet been established.
Millimeter values approximate 25.4 mm per inch. Meter values approximate 0.0254 m per inch.

Ref. C37.32

H. SURGE ARRESTERS

1. General

This section deals with the application of valve type surge arresters for the protection of equipment in substations. Although the surge arrester is the key component in insulation coordination, a complete description of the total concept of insulation coordination is beyond the scope of this bulletin.

Surge arresters are the basic protective devices against system transient overvoltages that may cause flashovers and serious damage to equipment. They establish a baseline of transient overvoltage above which equipment will be protected by operation of the arrester. When a dangerous transient overvoltage appears at an arrester location, the arrester sparks over internally and discharges the surge energy to ground. Once the overvoltage is reduced sufficiently, the arrester seals off the flow of power follow current through itself and the circuit is returned to normal. As voltage sensitive devices, arresters must be carefully correlated with the system operating voltages.

2. Classification of Arresters

Surge arresters are classified as station, intermediate, and distribution arresters. Classifications are determined by prescribed test requirements, listed in ANSI C62.1, Table 2 (see Appendix), Test Requirements for Arrester Classification. Their major characteristics are summarized in ANSI C62.2, Table 1 (see Appendix), Arrester Characteristics. All three classes may be used for application in substations.

Relative protective capabilities and initial costs of surge arresters decrease in the same order as listed in the preceding paragraph. Which arrester to use must be determined from an analysis of the protective characteristics required, the importance of the equipment protected, the level of reliability desired and the overall cost of protection.

REA Bulletin 43-5 should be referred to for a listing of surge arresters for use in substations of the borrower's systems.

a. Station Class Arresters

Station class arresters are more ruggedly constructed than either intermediate or distribution classes. They have greater surge current discharge ability and lower IR voltage drop, thus affording better protection. In the event of arrester failure, their ability to vent safely during high system short circuit currents is better than the other classes of arresters.

Station class arresters are recommended for all substations of large capacity (10,000 kVA and above) and on smaller substations that are of prime importance. They should be used on transmission circuits longer than approximately 100 miles or where shunt capacitor banks are installed.

Station class arresters are also desirable on substations using reduced insulation (BIL) or those located in high lightning exposure areas. They should be used where the system short circuit current exceeds the venting capability of intermediate class arresters. They are the only class arrester available for use on systems above 150 kV.

b. Intermediate Class Arresters

Intermediate class arresters may be used in substations rated below 10,000 kVA at a cost saving compared to station class arresters. Their electrical protective characteristics (sparkover and IR) are higher than station arresters, but are usually adequate for small substations. In the event of arrester failure, intermediate class arresters can safely vent with short circuit current of 16,000 amperes or less. Intermediate class arresters are available in ratings 3 kV through 120 kV.

c. Distribution Class Arresters

Distribution class arresters may be used on the low voltage side of distribution substations. They should be installed on the load side of feeder overcurrent protective devices (reclosers or breakers). They are frequently applied connected to the low voltage bushings of small distribution substation transformers. Their protective characteristics are not as good as either intermediate or station class

arresters. If distribution class arresters are used in substations, only the direct connected type with ground lead disconnector (isolator) should be used.

3. Ratings (Standard Definitions)

a. Voltage Rating (kV rms)

The designated maximum permissible operating voltage between its terminals at which an arrester is designed to perform its duty cycle. It is the voltage rating specified on the nameplate.

b. Power-Frequency Sparkover Voltage

The root-mean-square value of the lowest power frequency sinusoidal voltage that will cause sparkover when applied across the terminals of an arrester.

c. Impulse Sparkover Voltage

The highest value of voltage attained by an impulse of a designated wave shape and polarity applied across the terminals of an arrester prior to the flow of discharge current.

Standard wave shape is a 1.2 x 50 μs wave, i.e., a wave that rises to crest in 1.2 μs and decays to one-half crest value in 50 μs.

d. Discharge Current

The surge current that flows through an arrester when sparkover occurs.

e. Discharge Voltage

The voltage that appears across the terminals of an arrester during the passage of discharge current. Maximum values are usually available from the manufacturer for currents of 1.5, 3, 5, 10, 20, 40 kA with a wave shape of 8 x 20 μs.

The 8 x 20 μs standard wave shape is one that rises to crest in 8 μs and decays to one-half crest value in 20 μs.

f. Discharge-Voltage Current Characteristic

The variation of the crest values of discharge voltage with respect to discharge current.

4. System Voltage

System voltages carry two designations:

a. Nominal Voltage

Nominal voltage, which is the approximate phase-to-phase voltage distinguishing one system from another. The nominal voltage is the voltage by which the system may be designated and is near the voltage level at which the system normally operates. The nominal voltage is usually approximately 5 to 10 percent below the maximum system voltage.

b. Maximum System Voltage

Maximum system voltage, which is the highest rms phase-to-phase operating voltage that occurs, is the highest phase-to-phase voltage for which equipment is designed for satisfactory continuous operation without derating of any kind. It is the starting basis on which surge arresters are applied.

Maximum system voltages are generally those prescribed in ANSI C84.1, Voltage Ratings for Electric Power Systems and Equipment (60 Hz). On systems rated 230 kV and below, it is expected that the maximum system voltage may be 5 to 10 percent higher than nominal voltage.

5. Grounded vs Ungrounded Systems

Systems have been historically referred to as effectively grounded when coefficient* of grounding does not exceed 80 percent, or noneffectively grounded or ungrounded when coefficient* of grounding exceeds 80 percent.

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*The ratio E_{LG}/E_{LL}, expressed as a percentage, of the highest root-mean-square line-to-ground power-frequency voltage E_{LG} on a sound phase, at a selected location, during a fault-to-ground affecting one or more phases to the line-to-line power-frequency voltage E_{LL} which would be obtained, at the selected location, with the fault removed.

A value not exceeding 80 percent is obtained approximately when, for all system conditions, the ratio of zero sequence reactance to positive sequence reactance (X_0/X_1) is positive and less than three, and the ratio of zero-sequence resistance to positive-sequence reactance (R_0/X_1) is positive and less than one.

On certain distribution systems of the four-wire type where transformer neutrals and neutral conductors are directly grounded at frequent points along the circuit, the positive sequence resistance (R_1) may be significant due to small conductors, and should be considered.

Neglecting this component may result in higher rated arresters than normally required. In these cases, use ratios R_0/Z_1, and X_0/Z_1. The coefficient of grounding for such systems may be as low as 67 percent. On many high-voltage transmission systems, the coefficient of grounding may be as low as 70 percent. The possibility of increases in the coefficient of grounding due to system switching or changes should be recognized.

6. Application Guide

a. General

The voltage rating assigned to a surge arrester should exceed the maximum 60 Hz voltage across its terminals during normal or fault conditions. In general, the surge arrester voltage rating should be at least 25 percent higher than the phase-to-ground voltage when the system is operating at maximum phase-to-phase voltage.

On isolated neutral systems, which may be a delta system or an ungrounded-wye system, this rating should be approximately 105 percent of, and never less than, the maximum rating of the system. Such an arrester is called a "full rated" or 100 percent arrester. On effectively grounded systems, the arrester maximum rating can generally be 80 percent or less of the maximum system voltage. In special cases, arresters as low as 75 percent or even 70 percent of maximum system voltage rating may be applied, depending on the coefficient of grounding of the system.

b. Maximum Phase-to-Ground Voltage

The first step recommended in the general procedure to select a lightning arrester is to determine the maximum phase-to-ground power-frequency overvoltage at the arrester location. This maximum overvoltage may occur as a result of a fault condition, sudden loss of load or resonance. Overvoltages experienced as a result of loss of load or resonance are determined by system operating experience or by computer studies. Overvoltages that result from these two conditions are not expected to be significant for most applications at 230 kV and below.
Determination of the overvoltage due to a fault condition is necessary for any power system where less than full rated arresters are to be considered.

With regard to the overvoltage that results from a fault condition, the following is quoted from the ANSI C62.2 arrester application guide:

"....multiply the maximum system phase-to-phase operating voltage by the coefficient of grounding at the point of installation of the arrester. The value of the coefficient of grounding can be estimated from Exhibit 1 of USA Standard for Lightning Arresters for Alternating Current Power Circuits, C62.1. If curves in Exhibit 1 of C62.1 are not used and calculations are made for coefficient of grounding, then for machine characteristics the use of subtransient reactance is recommended."

c. Protective Margins

The lower the arrester rating on a given system, the greater is the protective margin for the insulation of the protected equipment. When system studies or calculations show that protective margins would be more than adequate, the BIL of major equipment may be reduced at substantial savings. Generally accepted practice is to provide a minimum margin of 20 percent between transformer BIL and surge arrester maximum IR, and 15 percent in the case of switching surges. Switching surge withstand strength of transformer insulations is usually specified at 83 percent of impulse BIL. Greater margins may be required where a condition of insulation degradation may be present.

The protective margins must be examined over the full volt-time characteristic of the insulation that is to be protected and the volt-time characteristics of the arrester. Sufficient margin must also be maintained regardless of the relative physical location of the arrester and protected equipment in the substation. The arrester should be located as close to the major equipment as possible, and the arrester ground resistance should be low. Surge arrester grounds should be reliably connected to the substation ground grid and with the frames of all equipment being protected.

d. Thermal Capacity

The arrester thermal capacity or ability to pass repeated or long duration surge currents (such as switching surges) without an internal temperature rise, which could fail the arrester, must be checked. This is especially true in all cases where there are long lines or shunt capacitor banks with high stored energy. Available switching surge energy increases as the square of the system voltage and directly with the length of lines. Thus, on 138 kV lines of equal length to 69 kV lines, the surge arresters must have at least four times the discharge capacity.

e. Direct Stroke Shielding

Surge arresters are applied primarily on the basis of their effectiveness in limiting overvoltages in the form of traveling waves entering the substation over connecting lines. High energy lightning strokes hitting a substation bus at or near the arrester could easily destroy the arrester while it is attempting to pass the surge current to ground. Even if the arrester is not destroyed, the protective margins provided may become nonexistent due to the effect of the steep fronts and high IR voltage produced by the arrester.

Therefore, a basic principle of surge arrester application is the provision of overhead ground wires and/or grounded conducting masts to shield the substation electrical equipment against direct lightning strokes. Effective shielding also permits greater separation of a surge arrester from the equipment being protected, since the overvoltage impulses are less steep and are usually of lower magnitude.

f. Multiple Lines

It is well recognized that the severity of lightning impulses arriving at a substation is reduced by the effect of multiple lines, because any traveling waves coming into a substation will divert part of the energy in the wave out over all line connections. It is difficult, however, to take full advantage of this, since one cannot be sure of the lines being connected when needed. Also, in substations with long buses, etc., the distances sometimes prevent effective use of this principle.

g. Standards and Guides

There are two principal national standards or guides pertaining to surge arresters:

(1) ANSI C62.1 (IEEE 28) Surge Arresters for Alternating-Current Power Circuits

This standard contains much basic information on arresters such as definitions, service conditions, classification and voltage ratings, performance characteristics and tests, test procedures, design tests, conformance tests and construction. Some pertinent sections are:

Section 3, Service Conditions

Standard arresters are designed for ambient temperatures not exceeding 40°C (104°F) and altitudes not exceeding 1800 meters (6,000 feet).

Section 4.1, Table 1 (See Appendix), Voltage In Kilovolts, lists the standard voltage ratings available in distribution, intermediate and station class arresters.

Section 4.2, Table 2 (See Appendix), Test Requirements for Arrester Classification, summarizes the sections dealing with test requirements for the different arrester classifications of distribution, intermediate and station.

Section 7.1, Table 3, Insulation Withstand Test Voltages, lists the various insulation requirements of all ratings of the different arrester

classifications, with the internal parts removed.

Section 7.8, Table 5 (See Appendix), Pressure-Relief Test Currents for Station and Intermediate Arresters, lists the symmetrical rms amperes short circuit capability of various ratings of station and intermediate arresters.

(2) ANSI C62.2 Guide for Application of Valve-Type Lightning Arresters for Alternating-Current Systems

This standard is an excellent guide on application of arresters for the more basic cases. It contains information on general procedures, step-by-step procedures for protection of transformers and substation equipment, protection of other equipment such as booster transformers, reactors, current transformers, etc. Of particular interest is Figure 2, Typical Voltage - Time Curve for Coordination of Arrester Protective Levels with Insulation Withstand Strength (see Appendix). This curve illustrates the protection provided by an arrester to transformer insulation.

Appendix A, Protective Characteristics of Lightning Arresters, contains data on protective characteristics of available arresters compiled from domestic manufacturers. This is very useful for general studies, but it should be kept in mind that the voltage values given are the maximums of the published protective characteristics. Specific manufacturer's information should be consulted for more accurate insulation coordination.

Appendix B, Switching Surges Liable to Cause Operation of the Arrester, provides important considerations concerning switching surges. It is generally necessary to consider switching-surge protective levels only for application on systems above 69 kV. In most cases, insulation coordination levels will not be affected by switching surges except at levels at 345 kV or above.

h. Guide Steps for Application of Valve-Type Surge Arresters for A-C Systems (See ANSI 62.2 Section 3 for details)

An example of surge arrester selection will be worked out along with each guide step to illustrate the procedure. The example is: arrester selection for a 230 kV substation coordinated with the transformer basic impulse insulation level (BIL). The 230 kV substation is supplied by one 230 kV line. Both the substation and the line are effectively shielded.

(1) Determine the maximum phase-to-ground power-frequency overvoltage at the arrester location. In most cases, this will depend on the coefficient of system grounding.

Example: At the surge arrester location, system parameters are known to be:

$$R1 = R2 = 0.1X1, \ \frac{R_0}{X_1} = 0.8 \text{ and } \frac{X_0}{X_1} = 2.5.$$

From curve (B) of Figure 1 (see Appendix) of ANSI C62.2, the coefficient of grounding is 75 percent. Maximum system voltage is 230 kV x 1.05 or 242 kV. Maximum phase-to-ground overvoltage during a ground fault is 242 kV x .75 or 181 kV.

(2) Estimate the waveshape and magnitude of arrester discharge current. The magnitude is determined largely by the effectiveness of the shielding against direct lightning strokes.

Example: The standard arrester discharge current curve (a 8 x 20 μs wave) represents the most severe current waveshape to be expected at a substation that is effectively shielded. Surge arrester discharge voltage characteristics (IR drop) are based on this standard curve. A conservative value of maximum current with effective shielding is 10 kA. The current could reach as high as 20 kA or higher if the substation is not effectively shielded.

(3) Tentatively select arrester class and voltage rating.

Example: A station type surge arrester must be selected, since this is the only type available at this voltage level. The substation size and importance may indicate a station type arrester regardless of system voltage. Arrester voltage rating must be at least 181 kV, as determined in Step 1. Another rule of thumb recommends that the arrester voltage rating be not less than 125 percent of the voltage to ground when the system is operating at maximum system voltage or 1.25 x 1.05 x 230 kV/ square root of 3 = 174 kV. The next standard arrester rating, above 174 kV and 181 kV, is 192 kV and is the tentative selection.

(4) Determine the impulse and switching surge protective levels of the tentatively selected arrester. The necessary information may be obtained from the arrester manufacturer or approximately from Appendix A of ANSI 62.2.

Example: Typical surge arrester characteristics are obtained from arrester manufacturer's published data. These characteristics include: maximum spark over (S.O.) on front-of-wave, maximum S.O. on full wave (1.2 x 50 (μs), maximum S.O. on switching surge (S.S.), maximum discharge voltage for 5, 10 and 20 kA of discharge current and minimum S.O. on 60 Hz voltage. Typical characteristics are shown plotted on Figure V-11 in the Appendix of this section.

(5) Calculate the maximum theoretical surge voltages that could appear at the insulation to be protected. This will depend on many factors, such as effectiveness of shielding, number of lines normally connected, and relative location of arrester to protected equipment.

Example: For most applications, it is sufficient to rely on the recommended minimum margins between protection levels provided by the surge arrester and the BIL of the protected equipment. See Item (7).

(6) Calculate the minimum permissible withstand strength of the insulation to be protected. The necessary information may be obtained from manufacturers of the equipment or approximately from applicable standards on the type of equipment.

Example: The impulse withstand strength of equipment is defined by its full-wave impulse test voltage using a standard 1.2 x 50 μs wave. The strength is greater for shorter duration voltage peaks. See Figure V-11 in the Appendix of this section for curves showing withstand strength of a power transformer over the range from 0 to 5,000 μs.

(7) Evaluation of insulation coordination (F.O.W. 20 percent; Maximum Discharge 20 percent; Maximum Switching Surge 15 percent).

Example: See Figure V-11 in the Appendix of this section for the coordination of surge arrester protective levels with 230 kV transformer BILs. Possible BILs of 900, 825, 750 and 650 kV are shown. All BILs are adequately protected from impulses or switching surges. However, other factors must be considered such as 60 Hz withstand, both internal and external; future deterioration of the insulation, surge arrester location with respect to the transformer, etc. A BIL of 750 kV would appear to be a proper choice based on the conditions assumed. The surge arrester voltage rating of 192 kV is a proper selection unless there are unusual system conditions that could subject the arrester to voltages above its rating.

(8) When coordination cannot be achieved (alternate means to consider). Solution may be to select a different arrester, improve arrester location relative to protected equipment, increase insulation level of protected equipment, improve shielding or install additional arresters.

7. Location

a. General

In general, surge arresters should be located at or near the main transformers on both high and low voltage sides. It may be desirable to also locate arresters at the line entrances or in some cases on a bus that may be connected to several lines. They should be located to give maximum possible protection to all major substation equipment.
In many cases, the arresters protecting the main transformer may be mounted directly on the transformer.

Since lightning strokes can produce surges with steep wave fronts, voltage gradients, reflections or oscillations and high rates of rise of current, which can result in large differences in the line-to-ground voltage between even closely spaced points, it is extremely important to locate the arresters as close as practical to the apparatus requiring protection. The arrester lead length should be kept as short as practical. Following is a general guide for determining maximum separation distances between arrester lead tap and transformer, considering the effect of arrester lead length:

b. Arrester Separation Distance and Lead Length

(1) The voltage impressed on the substation transformer after arrester operation may be much higher than the arrester discharge voltage if either arrester separation distance (S) or lead length (L) is excessive. Consequently, these factors must always be considered in applying arresters. Application curves have been developed to facilitate this.

(2) Arrester separation distance (S) is defined as the distance from the line arrester lead junction to the transformer bushing. Voltage reflections result when the discharge voltage traveling as a wave arrives at the transformer. If the arrester is very close to the transformer, these reflections are cancelled almost instantaneously by opposite polarity reflections from the arrester. As the separation distance increases, the cancellation becomes less and less effective, and the

voltage at the transformer may increase to almost twice the arrester discharge voltage.

(3) Arrester lead length (L) is defined as the total length of the conductor from the junction of the surge arrester lead with the line or transformer circuit to physical ground, but not including the length of the arrester itself. When the arrester discharges, surge current flows to ground over the lead length. The resulting voltage drop, L di/dt, is proportional to the lead length and adds to the arrester discharge voltage.

(4) The increase in surge voltage due to separation distance and lead length may be evaluated by the method given in Reference 1. It will be satisfactory, however, to use the application curves from this reference and reproduced as Figures V-8, 9, and 10 to determine maximum lead lengths and separation distances for high side arresters, provided that modern arresters are used. For this purpose, any arrester manufactured in the USA during or after 1960 may be considered modern.

c. Special Situations

(1) On smaller substations with a high side fuse, the arrester should be located on the line side so as to prevent the lightning discharge from passing through the fuse.

(2) Arresters need not be installed on the line side of high voltage air break switches. However, they should be connected close enough to protect the switch adequately when the switch is closed. Line entrance gaps may be used on the line side for protection when the switch is open. See Paragraph 8, Protection at Line Entrances.

(3) Arresters of the valve type may be installed on the low voltage distribution side. They should be installed on the load side of the feeder overcurrent device (recloser, fuse, or circuit breaker) and any related disconnecting switch.

(4) Continuous metallic sheath cables from substation to overhead lines should be protected by arresters at the junction, and should be grounded effectively at the base of the cable terminal structure and directly to the cable sheath. If the overhead line is unshielded, additional protective devices may be required a few spans before the junction.

The cable sheath should be bonded to the substation ground at the substation end. It may also be necessary to install arresters at the substation equipment end if the cable is such that two times the protection level of the junction arrester exceeds 80 percent of the substation BIL. This is due to reflection at the equipment end.

(5) On high voltage wye connected transformers with ungrounded neutral, voltage reflections at the neutral can approach two times the voltage applied simultaneously at the line terminals. It is therefore necessary to employ a surge arrester from neutral to ground to limit these surge voltages, especially if the transformer has graded insulation. The rating of the arrester should be approximately 1.2 times the normal line-to-neutral system voltage.

8. Protection at Line Entrances

Lightning wave fronts may approach 1000 kV/μs, resulting in a gradient of 3.3kV/m difference in line-to-ground potential. Most, however, do not exceed 500 kV/μs, and this value is considered a basis for good practice. At open circuit points, these waves are reflected back at nearly double the original rate of rise, increasing the possibility of a flashover or equipment damage close to that point. It is apparent that protection should be considered for the line entrances on large substations, especially where line breakers and disconnect switches may be open, constituting dead end reflections. Surge arresters will provide the most effective means of protection, but line entrance gaps may be sufficient. Line entrance protective gaps may be considered as an economic alternative to surge arresters at substation entrances of all overhead lines 23 kV and above to provide additional protection for substation insulation under the following conditions:

When steep front incoming surges would break down insulation near the line entrance or on the bus. (Station arresters may be too far distant to provide adequate protection.) When part of the station insulation is isolated from protective influence of the station arresters by switching. When the station arrester has been damaged or otherwise removed from service so that its protection is not available.

REFERENCES

1. Simplified Method for Determining Permissible Separation Between Arresters and Transformers, AIEE Transactions Paper 63-229.

2. References contained in ANSI Standard C62.2, Section 6.

APPENDIX

TO

SURGE ARRESTERS

Table 1
Voltage Ratings in Kilovolts

Secondary Arresters	Distribution Arresters	Intermediate Arresters	Station Arresters
0.175			
0.650			
	1		
	3	3	3
	6	6	6
	9	9	9
	10		
	12	12	12
	15	15	15
	18		
	21	21	21
		24	24
	25		
	27		
	30	30	30
		36	36
		39	39
		48	48
		60	60
		72	72
		90	90
		96	96
		108	108
		120	120
			144
			168
			180
			192
			240
			258
			276
			294
			312
			372
			396
			420
			444
			468
			492
			540
			576
			612
			648
			684

NOTE: Because of the more stringent requirements for the protection of rotating machines, the use of arresters (all classes) rated 4.5, 7.5, 16.5, 18, 19.5, 22.5, 24, 25.5, and 27 kV is recognized for this application.

Ref. C62.1

Table 2
Test Requirements for Arrester Classification

Arrester Classification	Standard Ratings kilovolts	Section Reference: Duty-Cycle Test	Discharge-Current Withstand Tests	Insulation Withstand Tests	Pressure-Relief Tests	Contamination Test
Station Valve	3 through 684	7.6.1	7.5.1, 7.5.2	7.1	7.8	7.10
Intermediate Valve	3 through 120	7.6.1	7.5.1, 7.5.2	7.1	7.8	7.10
Distribution Valve	1 through 30	7.6.1	7.5.1, 7.5.2	7.1		7.10
Distribution Expulsion	3 through 18	7.6.2	7.5.1	7.1		
Secondary Valve	0.175 and 0.650	7.6.1	7.5.1	7.1		
Protector Tubes	13.8 to 138	7.6.2	7.5.1	7.1, Table 3 Note (2)		

Table 5
Pressure-Relief Test Currents for Station and Intermediate Arresters

	Symmetrical rms Amperes: High Current (Minimum)		Low Current
Station Arresters	† Class I	Class II	
3 - 15 kV ratings*	65 000	25 000	400–600
21 - 192 kV ratings	40 000	25 000	400–600
240 - 294 kV ratings	25 000	25 000	400–600
Intermediate Arresters	Class III		
3 - 120 kV ratings*	16 100		400–600

* Test values for arresters with porcelain tops have not been standardized.
† Preferred rating.

Ref. C62.1

Table 1
Arrester Characteristics

Class*	Range of Application Max System Voltage (kV)	Protective Level† Per Unit Crest Arrester Rating (S.O.)	Protective Level† Per Unit Crest Arrester Rating (IR at 10 kA)	Thermal Capability‡ (1) Duty Cycle Initiating Surge (Crest Amperes)	Thermal Capability‡ (2) Transmission Line Discharge (Miles)	Thermal Capability‡ (3) Low-Current Long Duration Withstand (Crest Amperes μs)	Thermal Capability‡ (4) High-Current Short-Time Withstand (Crest Amperes)	Pressure Relief § (rms Symmetrical Amperes)
Station	2.6-765	2.8-1.9	2.1-1.7	10 000	150-200 (No Standard above 400 kV)	Not rated	100 000	65 000-25 000
Intermediate	2.6-150	2.8-2.2	2.5-2.4	5000	100	Not rated	65 000	16 100
Distribution	2.6-37	5.9-2.5**	4.1-3.0	5000	Not rated	75-1000	65 000	Not rated

†This refers to front-of-wave impulse sparkover (S.O.) and discharge voltage (IR) characteristics. The per unit values shown are maximum industry values from tables in Appendix A. For specific values, consult manufacturers literature.

‡This refers to the ability of the arrester to protect itself against the thermal stresses resulting from:

(1) Power follow current (which also determines the ability to reseal against a voltage equal to the arrester rating).

(2) The number of line miles an arrester can discharge, which is a measure of its ability to handle switching surges (see Appendix B). The general relationship (for overhead lines only) is:

$$D = 6.76\,\frac{D_L}{Z_L} \times \frac{Z}{S^2}$$

where

D = line miles

Z = line surge impedance

S = switching surge overvoltage, line to ground, per unit of maximum line to ground system voltage

For D_L, Z_L, see Table 4, and Section 1:7.4.2.1.2, USA Standard C62.1-1967. The use of this formula is valid only for values of D, Z, and S within about 25 percent of the values of D_L, Z_L, and E_L.

See References [14] and [15].

(3) Long duration lightning.

(4) Severe lightning discharges.

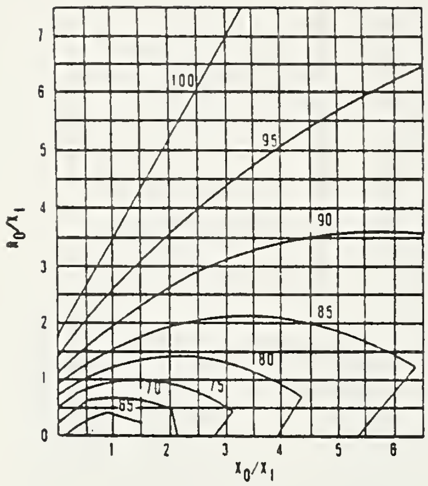
§This refers to ability of the arrester to withstand the system's asymmetrical (1.55 × symmetrical value) short circuit current at the point of installation without exploding in case of internal failure of arrester.

**Without external gap.

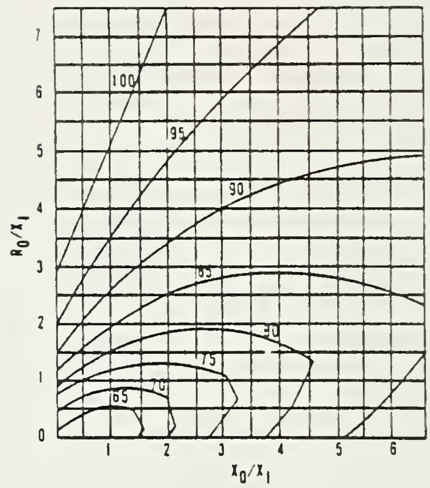
*Typical Applications:

Station - Large high-voltage stations (5000-10 000 kVA and above).
Intermediate - Small to medium stations at all voltages within range of application.
Distribution - Small distribution substations, feeders, and distribution transformers.

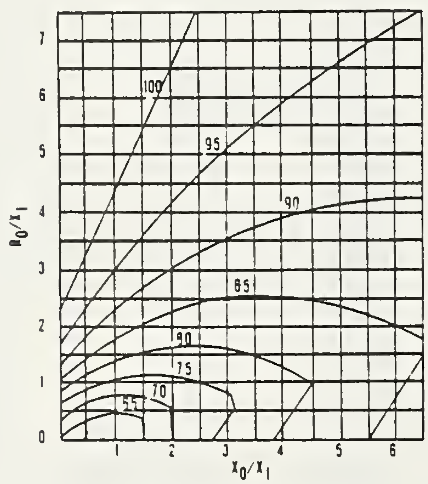
Ref. C62.2



(A)
Voltage Conditions Neglecting Positive- and Negative-Sequence Resistance. $R_1 = R_2 = 0$



(C)
Voltage Conditions for $R_1 = R_2 = 0.2\ X_1$



(B)
Voltage Conditions for $R_1 = R_2 = 0.1\ X_1$

NOTE: Numbers on curve indicate coefficient of grounding for any type of fault for arresters bounded by curve and axes of the curves. All impedance values must be on the same kVA base or in ohms on same voltage base.

For all curves:

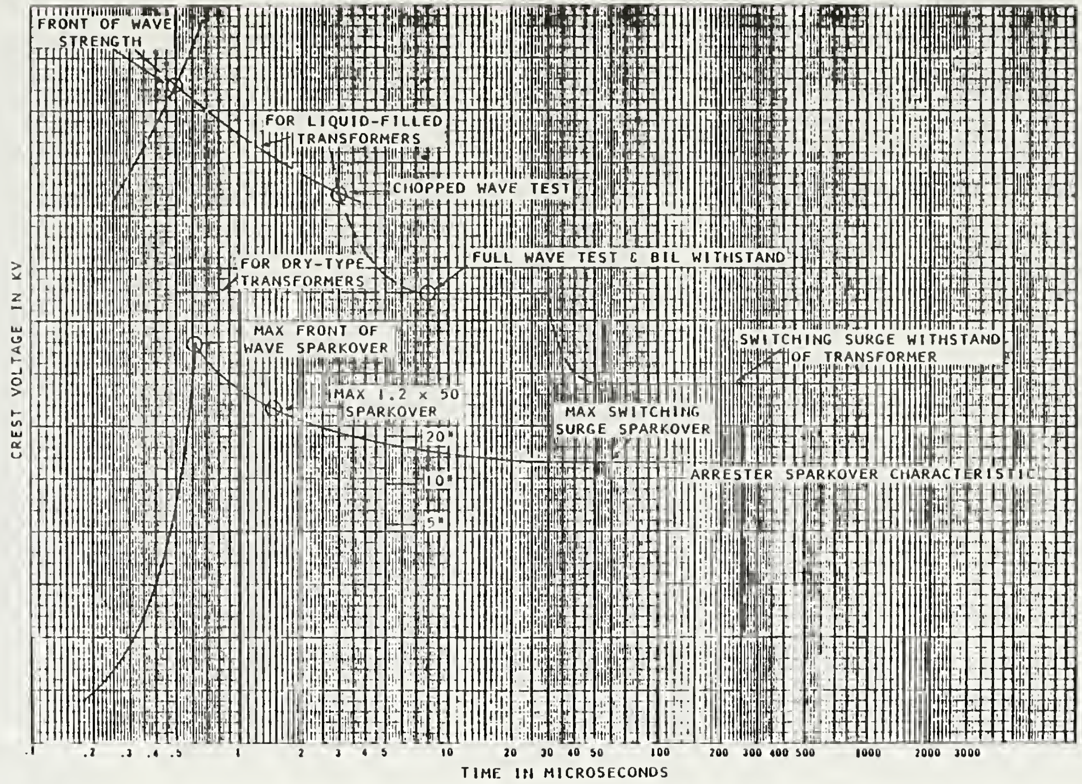
R_0 = zero-sequence resistance
R_1 = positive-sequence resistance
R_2 = negative-sequence resistance
X_0 = zero-sequence inductive reactance
X_1 = positive-sequence subtransient reactance
X_2 = negative-sequence reactance
$X_1 = X_2$

The effect of fault resistance was taken into account. The resistance which gives the maximum voltage to ground was the value used. The discontinuity of the curves is caused by the effect of fault resistance.

These data are from Transmission and Distribution Reference Book, Westinghouse Electric Corp. Pittsburgh, Pa., 1950.

Fig. 1
Coefficient of Grounding for Various System Conditions

Ref. C62.2



*Lightning arrester maximum discharge voltage based on a 8 × 20 current wave having the specified magnitude in kiloamperes.

Fig. 2
Typical Voltage-Time Curve
for Coordination of Arrester Protective Levels
with Insulation Withstand Strength

Ref. C62.2

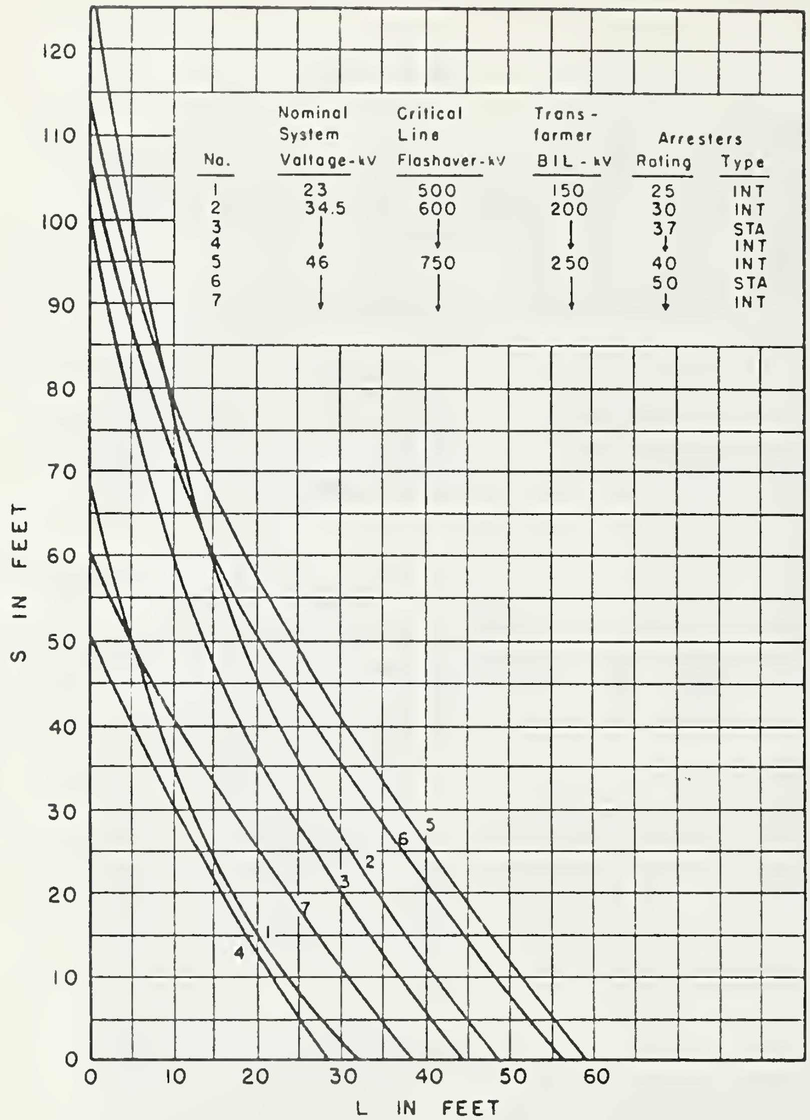


FIGURE V-8 - MAXIMUM SAFE SEPARATION DISTANCE OF LIGHTNING ARRESTERS FROM PROTECTED EQUIPMENT. NOMINAL SYSTEM VOLTAGE 23 KV THROUGH 46 KV. (L = ARRESTER LEAD LENGTH, S = SEPARATION)

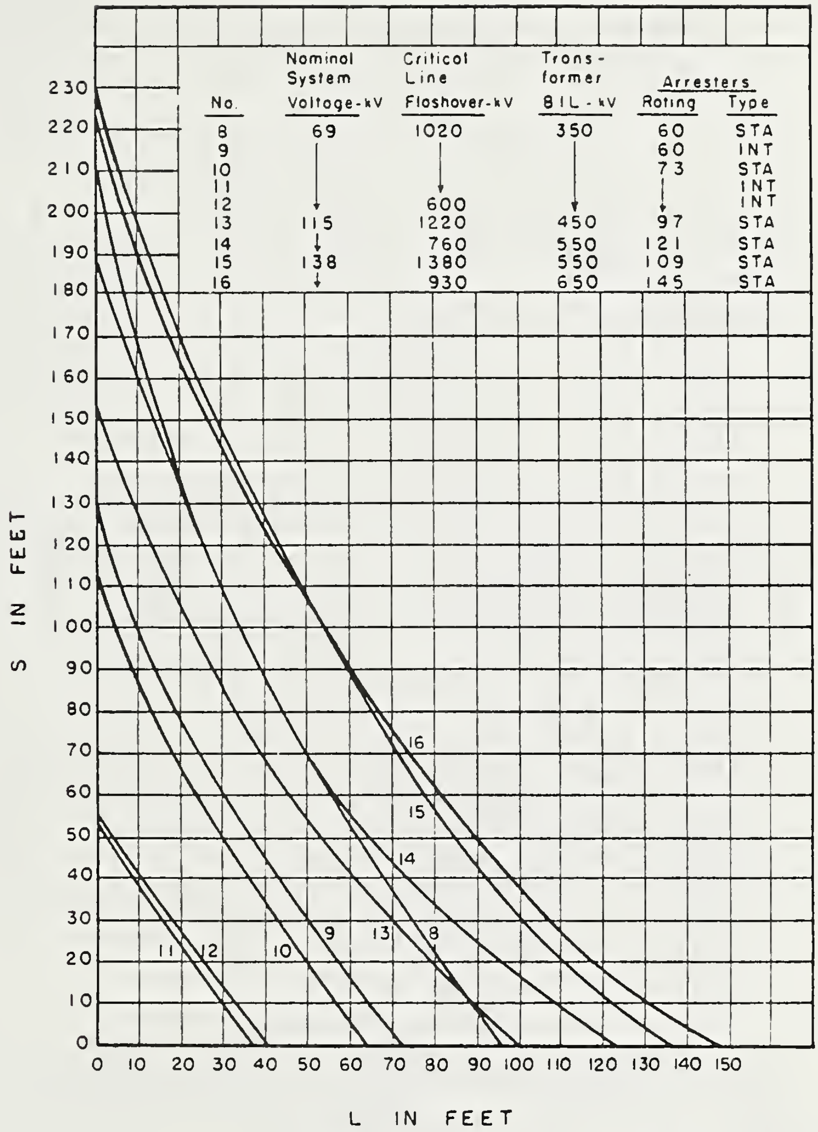


FIGURE V-9 - MAXIMUM SAFE SEPARATION DISTANCE OF LIGHTNING ARRESTERS FROM PROTECTED EQUIPMENT. NOMINAL SYSTEM VOLTAGE 69 KV THROUGH 138 KV. (L = ARRESTER LEAD LENGTH, S = SEPARATION)

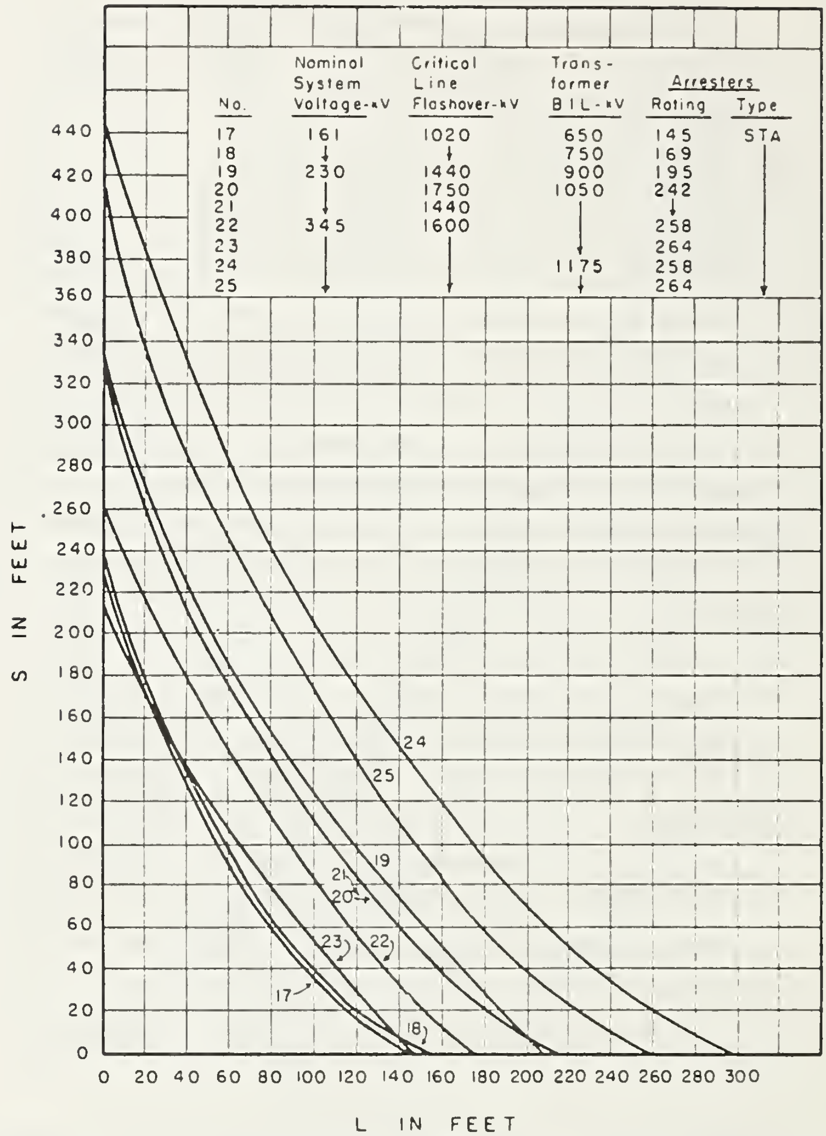


FIGURE V-10 - MAXIMUM SAFE SEPARATION DISTANCE OF LIGHTNING ARRESTERS FROM PROTECTED EQUIPMENT. NOMINAL SYSTEM VOLTAGE 161 KV THROUGH 345 KV. (L = ARRESTER LEAD LENGTH, S = SEPARATION)

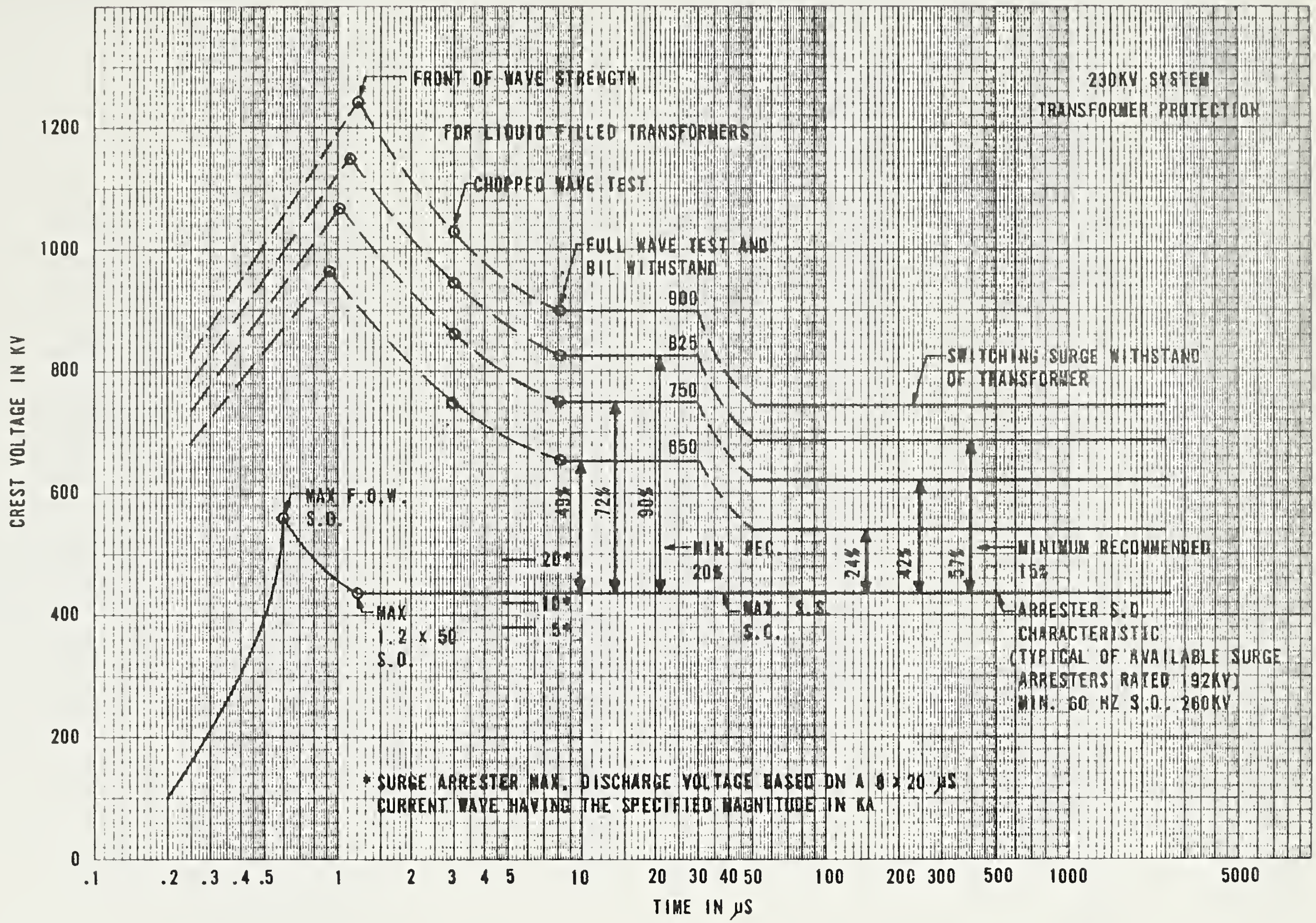


FIGURE V-11

TYPICAL VOLT-TIME CURVES FOR COORDINATION OF SURGE ARRESTER PROTECTIVE LEVELS WITH INSULATION WITHSTAND STRENGTH

I. AUTOMATIC CIRCUIT RECLOSERS

1. General

This section covers single-phase and three-phase alternating-current automatic circuit reclosers.

An automatic circuit recloser is a self-controlled protective device to interrupt and reclose automatically an alternating-current circuit through a predetermined sequence of opening and reclosing followed by resetting, lockout or hold closed.

a. Purpose

Reclosers are installed to provide maximum continuity of service to distribution loads, simply and economically,
by removing a permanently faulted circuit from the system or by instant clearing and reclosing on a circuit subjected to a temporary fault caused by lightning, trees, wildlife or similar causes. Unlike fuse links, which interrupt either temporary or permanent faults indiscriminately, reclosers are able to distinguish between the two types of faults, permanent and temporary. They give temporary faults repeated chances to clear or to be cleared by a subordinate protective device. If the fault is not cleared, the recloser recognizes the fault as permanent and operates to lock out or in some applications, holds closed (see Paragraph 5 d).

b. Application

Automatic circuit reclosers are used in distribution substations and on branch feeders to protect distribution circuits and to switch them. (Refer to Figure V-12.)

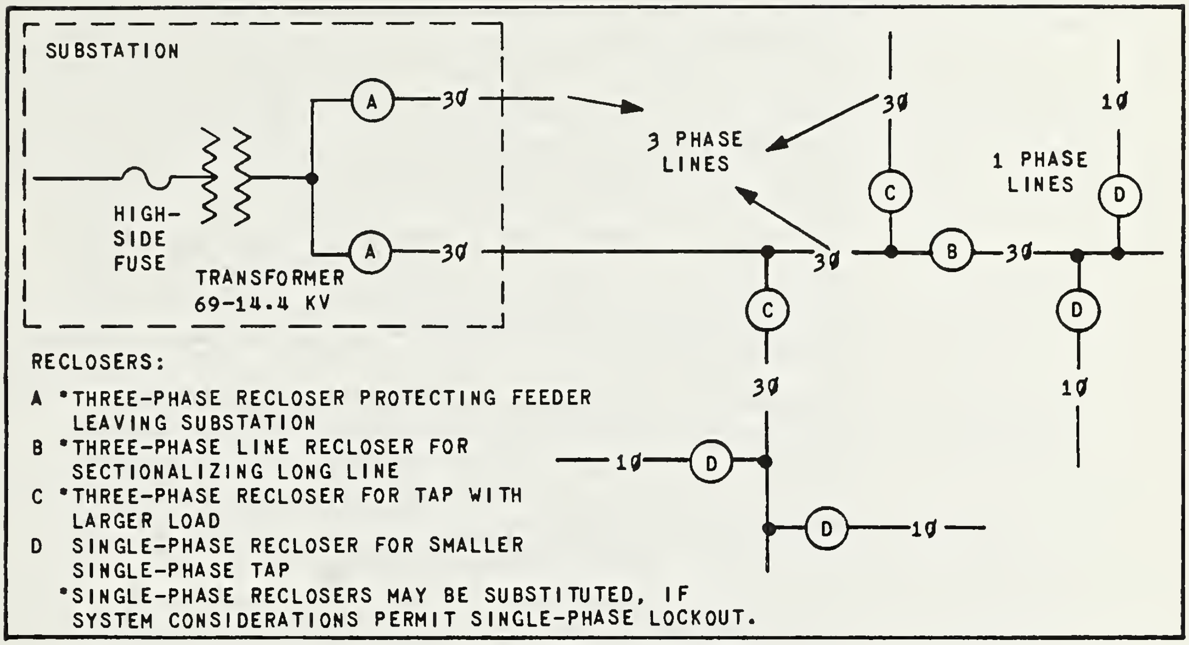


FIGURE V-12
TYPICAL LINE DIAGRAM OF DISTRIBUTION CIRCUIT
SHOWING APPLICATION OF RECLOSERS

Their proper application requires a study of the load and short circuit characteristics of both the protecting and the protected equipment. This includes high voltage fuses or other protection in the supply to a substation transformer bank, a circuit breaker or reclosers at the distribution voltage supplying the feeder at the substation, various line reclosers, sectionalizers, line fuses, the wire arc burn-down characteristic at the fault location, ground resistance, etc. In selecting reclosers, it is recommended that the procedure outlined in ANSI Standard C37.61, Paragraph 4.3, should be followed.

c. Service Conditions

Reclosers are suitable for operation at their standard rating within an ambient temperature range of +40°C to -30°C (104°F to -22°F) and at altitudes not exceeding 1000 meters (3300 feet). They may be applied at higher or lower temperatures, but performance may be affected and the manufacturer should be consulting regarding special considerations for such applications. They also may be applied at altitudes higher than 1000 meters (3300 feet), provided that corrections (reductions) are made in impulse insulation level, rated maximum voltage and rated continuous current. Correction factors (multipliers) are given in Table V-5, Columns 3 and 4. Reclosers designed for standard temperature rise may be used above an altitude of 1000 meters (3300 feet) at normal current rating without exceeding ultimate standard temperature limits, provided that the ambient temperature does not exceed the maximum +40°C limit reduced by the correction factor given in Table V-5, Column 5.

The rated interrupting current, current related required capabilities and rated interrupting time are not affected by altitude.

TABLE V-5
ALTITUDE CORRECTION

Altitude		Correction Factor (Multiplier)		
(1) Feet	(2) Meters	(3) Voltage Rating	(4) Current Rating	(5) Ambient Temp
3300	1000	1.00	1.00	1.00
4000	1200	0.98	0.99	0.99
5000	1500	0.95	0.99	0.98
10000	3000	0.80	0.96	0.92
16000	4900	0.63	0.93	0.85

d. Standards

Applicable ANSI and IEEE Standards (listed below) are comprehensive and valuable references when ACRs are being considered. REA Bulletin 43-5, "List of Materials for Use on Systems of REA Electrification

Borrowers," should be consulted for manufacturer's types of ACRs.

ANSI C37.60 (IEEE No. 437), "Requirements for Automatic Circuit Reclosers for Alternating-Current Systems"

ANSI C37.61 (IEEE No. 321), "Guide for the Application, Operation and Maintenance of Automatic Circuit Reclosers"

2. Recloser Classifying Features

Major classifying features in automatic circuit reclosers are described in the following paragraphs:

a. Single Phase or Three Phase. Both single phase and three-phase reclosers are available to satisfy application requirements.

(1) Single-phase reclosers are used to protect single-phase lines, such as branches or taps of a three-phase feeder. They can also be used on three-phase circuits where the load is predominantly single phase. Thus, when a permanent phase-to-ground fault occurs, one phase can be locked out while service is maintained to the remaining two-thirds of the system.

(2) Three-phase reclosers are used where lockout of all three phases is required for any permanent fault. They are also used to prevent single-phasing of three-phase loads, such as large three-phase motors. Three-phase motors. Three-phase reclosers have two modes of operation.

(a) The first, single-phase trip and three-phase lockout consists of three single-phase reclosers mounted in a single tank, with mechanical interconnection for lockout only. Each phase operates independently for overcurrent tripping and reclosing. If any phase operates to lockout condition due to a permanent fault, the mechanical linkage trips open the other two phases and locks them open. Thus, extended single-phase energization of three-phase loads is prevented. This type operation is provided for smaller recloser types.

(b) Larger reclosers make use of the second mode of operation: three-phase trip with three-phase lockout. For any fault - single-phase-to-ground, phase-to-phase, or three-phase - all contacts open simultaneously for each trip operation. The three phases, mechanically linked together for tripping and reclosing, are operated by a common mechanism.

b. Control Intelligence

The intelligence that enables a recloser to sense overcurrents, select timing operation, time the tripping and reclosing functions, and finally lockout, is provided by its control. There are two basic types of control schemes used: integral "hydraulic" control, or "electronic" control located in a separate cabinet. A recloser employs one of these controls.

(1) Hydraulic recloser control is used in all single-phase reclosers and in smaller ratings of three-phase reclosers. It is built as an integral part of the recloser. With this type of control, an overcurrent is sensed by a trip-coil connected in series with the line. When the over-current flows through the coil, a plunger is drawn into the coil to trip open the recloser contacts. Timing and sequencing are accomplished by pumping oil through separate hydraulic chambers or ducts.

(2) Electronic recloser control is used with larger three-phase reclosers. Compared to the hydraulic control, it is more flexible, more easily adjusted and more accurate. The electronic control, housed in a cabinet separate from the recloser, conveniently permits changing timing, trip current levels and sequences of recloser operations without de-energizing or untanking the recloser. A wide range of accessories is available to modify the basic operation, solving many different application problems.

Line current is sensed by special sensing current transformers in the recloser. The recloser and control are connected by a multiconductor control cable that carries sensing transformer secondary

currents to the control and the necessary trip and reclose signals from the control to the recloser. A dc battery supplies the control, assuring adequate operating power under all fault conditions.

c. <u>Tripping</u>

Series coil and non-series coil tripping are characteristics of individual classifications of reclosers.

(1) Series coil tripping is used on all single-phase reclosers and some three-phase reclosers. Sensing of fault current is provided by a series-connected solenoid coil that carries its rated line current. When a fault occurs, tripping is initiated by the solenoid plunger. The plunger, normally held at rest by the closing springs, is pulled into the coil and causes overtoggling of trip springs in the operating mechanism that opens the recloser contacts.

Tripping simultaneously charges closing springs that then close or reclose the recloser when the proper closing signal is present, thus making the recloser ready for another tripping operation.

(2) Non-series coil tripping is used only on some three-phase reclosers. It may consist of a tripping solenoid, energized from an external power supply, that over-toggles tripping springs in the same manner as performed by the series-trip solenoid. It may also consist of a tripping spring simply released by a small tripping solenoid also externally energized. In both cases, the tripping spring is previously charged by a closing solenoid or closing motor during a closing or reclosing operation of the recloser.

d. <u>Closing</u>

Various methods of closing and reclosing are available, depending upon the recloser selected.

(1) Spring closing is utilized on most single phase reclosers and some three phase reclosers. In each case, the closing spring is charged during a previous tripping operation.

(2) Solenoid closing is utilized on some single phase reclosers and some three phase reclosers. The solenoid coil may be high voltage ac and connected line-to-grounded neutral or it may be low voltage dc energized from a battery. A low voltage rectifier accessory is also available to permit use of local ac power supply for closing. Solenoid closing charges the tripping springs in preparation for the next tripping operation.

(3) Motor closing is utilized on some three phase reclosers. The motor charges closing springs and forces their overtoggle to close the recloser. The closing spring action simultaneously charges the tripping springs. The motor is energized from an external power supply.

e. Interrupter Types

Reclosers utilize either oil or vacuum as the interrupting mediums.

(1) Oil interruption is utilized on most single phase reclosers and some three phase reclosers. Reclosers utilizing oil for current interruption use the same oil for basic insulation. Most reclosers with hydraulic control also use the same oil for timing and counting functions.

(2) Vacuum interruption is utilized on a few single phase reclosers and some three phase reclosers. It has the advantages of lower maintenance frequency and minimum external force reaction during interruption. Vacuum reclosers may utilize either oil or air as the basic insulating medium, depending upon the recloser selected.

Note:

The term "Type" is a manufacturer's designation to identify each particular group or family of reclosers that he produces. It covers the major classifying features and certain rating and performance characteristics.

REA Bulletin 43-5 lists manufacturers' types of reclosers, some on a conditional basis.

3. Ratings

Automatic circuit reclosers are rated in terms of various voltages, frequency, continuous current, minimum tripping current, interrupting current and making current. In operating a recloser, the limitations imposed by a given recloser rating must not be exceeded in any respect; otherwise, excessive maintenance or unsatisfactory operation may be experienced.

a. Voltage Rating

(1) Nominal voltage specifies the nominal system voltage to which the recloser is intended to be applied.

(2) Rated maximum voltage indicates the highest voltage at which the recloser is designed to operate. Voltage ratings of automatic circuit reclosers are shown in ANSI C37.60, Tables 2A and 3A (see Appendix).

Note:

Some reclosers can be operated at system voltages lower than rated voltage. Series coil, hydraulically operated reclosers can be applied at a lower voltage without modification, and in some such cases may gain an increase in interrupting current capability. Non-series coil - shunt coil closing, spring tripping - reclosers can be applied at a lower voltage by installing a closing coil of the appropriate system voltage rating. No charge is necessary if the closing coil is low voltage and is supplied from an external ac or dc auxiliary power source. Manufacturers and their literature should be consulted for proper application of reclosers at voltages lower than rated voltage.

(3) Rated Impulse Withstand Voltage

Rated impulse withstand voltage of reclosers is a performance characteristic specified in ANSI C37.60 as a test requirement. This test demonstrates the ability of the recloser to withstand lightning and other fast impulse voltages. The voltage wave is the standard 1.2 x 50 μS wave

and may be either positive or negative polarity, depending on which gives the lower insulation strength.

b. Rated Frequency

The rated frequency of reclosers is 60 Hz. The manufacturer should be consulted if operation at other frequencies is being considered.

c. Rated Continuous Current

The rated continuous current is the magnitude of current in rms amperes that the recloser is designed to carry continuously. The present continuous current ratings of automatic circuit reclosers are shown in ANSI C37.60, Tables 2A and 3A (see Appendix). In many cases, the basic continuous current rating of a given recloser is limited by the series trip solenoid coil rating installed in the recloser. Therefore, as load current requirement increases, it is only necessary to replace the solenoid coil with one having a larger rating. (Ref. ANSI C37.60, Tables 2B & 3B in the Appendix.)

d. Rated Minimum Tripping Current

(1) The rated minimum tripping current is the minimum current at which a magnetically operated series coil recloser will perform a tripping operation. Standard tripping pickup is 200 percent of the continuous current rating of the recloser coil. Some reclosers are adjustable above or below the standard tripping pickup value.

(2) The minimum tripping current for shunt trip reclosers is variable and has no relation to the rated continuous current. Information on specific reclosers should be obtained from the manufacturer.

(3) The differential between minimum trip and continuous current ratings normally provides sufficient margin for load inrush current pickup after an extended outage on a feeder circuit.

e. Rated Symmetrical Interrupting Current

The rated interrupting current is the maximum rms symmetrical current that a recloser is designed to interrupt under the standard operating duty, circuit boltage, and specified circuit constants. (Ref. ANSI C37.60, Tables 2A, 2B, 3A and 3B in the Appendix.) This rating is stated on the nameplate. It is based on the capability of reclosers to interrupt the corresponding asymmetrical current in circuits having minimum X/R values as given in Column 13 of Tables 2A and 3A with a normal frequency recovery voltage equal to the rated maximum voltage of the recloser.

(X/R is the ratio of reactance to resistance of a circuit at rated frequency. The rms value of asymmetrical fault current at any time after initiation of the fault is dependent upon the instantaneous voltage existing at the moment the fault is initiated and upon the decrement of the direct current component, which is determined by the X/R value of the circuit.)

The following multiplying factors produce the maximum rms value of asymmetrical current at one-half cycle corresponding to the rated interrupting current:

X/R	Multiplying Factor
8	1.39
10	1.44
12	1.48
14	1.51
16	1.53

f. Rated Making Current

The rated making current is the same value as the rated interrupting current, including the corresponding asymmetry. The recloser must be capable of closing and latching closed against the rated making current and hold closed until a tripping sequence is initiated.

4. Construction

An automatic circuit recloser consists of five major components: tank, bushings, mechanism, interrupter, and controls. The following paragraphs describe these components.

a. Tank

The tank is that part of the recloser that houses the interrupter and tripping and closing mechanisms. The tank is usually made of steel and is rectangular for a three-phase recloser and cylindrical for a single-phase recloser. The top is usually an aluminum casting that supports the various components.

b. Bushings

The bushings are the insulating structures including through-conductors with provision for mounting on the top of the recloser.

c. Operating Mechanism

The operating mechanism of an automatic circuit recloser provides the power to open, close, reclose, lock out, or hold-closed the main contacts. The tripping mechanism is the device that releases the holding means and opens the main contacts. In most cases, the opening force is furnished by springs that are charged by the closing mechanism.

The closing mechanism is a solenoid coil, springs or a motor and gear arrangement. The closing force serves to close the main contacts and at the same time charges the opening springs. The lockout mechanism is the device that locks the main contacts in the open position following the completion of the sequence of operation. The hold-closed mechanism is the device that holds the main contacts in the closed position following the completion of a predetermined sequence of operation. It holds the main contacts closed as long as current flows in excess of a predetermined value. When the current is reduced below this value, the hold-closed mechanism resets to its initial position.

d. Interrupter

The interrupter is that part of the recloser that contains separable contacts, which operate within an interrupting unit. The physical configuration and method of interruption varies with manufacturer and recloser classification.

e. Control

Reclosers are provided with sequence control devices and operation integrator to change the recloser from instantaneous operations to time-delay operations and to lock out the recloser after a prescribed number of operations. Individual tripping operations of a recloser can be made to follow instantaneous or time-delay, time-current characteristics. Reclosers are normally set for one of the following sequences of operations:

Four time-delay operations

One instantaneous operation followed by three time-delay operations

Two instantaneous operations followed by two time-delay operations

There are a number of different sequence control devices that may be roughly classed into three types, namely, hydraulic type, an oil pump attached to the recloser plunger raises a trip piston a certain distance with each operation of the recloser. This trip piston establishes the sequence of fast and delayed tripping operations and eventually locks the recloser open. In the mechanical type, the trip piston is mechanically operated by the lift rod one notch at a time to accomplish this sequencing. The electronic type of control utilizes solid-state circuitry to provide the intelligency for performing all the command functions for automatic operation. Manufacturer's literature should be consulted for ratings and arrangements of electronic components available.

5. Operation

When an overcurrent of sufficient magnitude flows through the trip coil, the tripping action is initiated and the contacts are opened. The recloser contacts then reclose following a predetermined length of time. (Refer to Figure V-13). By the time the recloser has reclosed the circuit, the sequence control device has moved to count the trip operation. If the fault still persists on the circuit when the recloser closes, the tripping and reclosing sequence is repeated a predetermined number of times, as

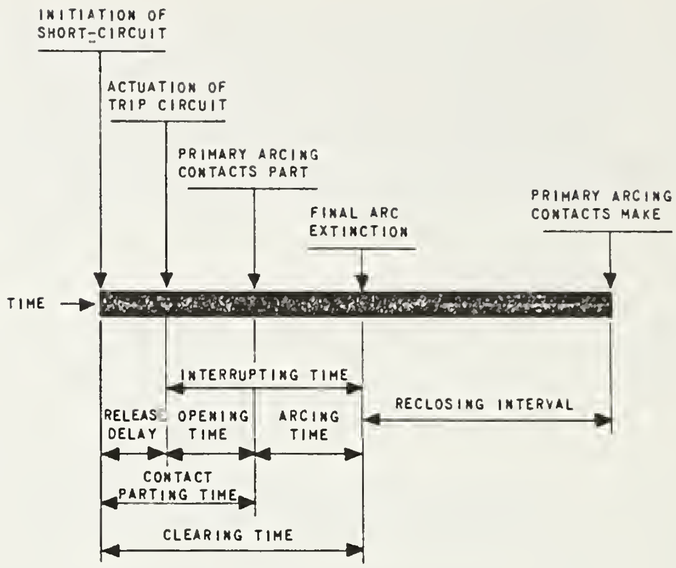


FIGURE V-13 UNIT OPERATION

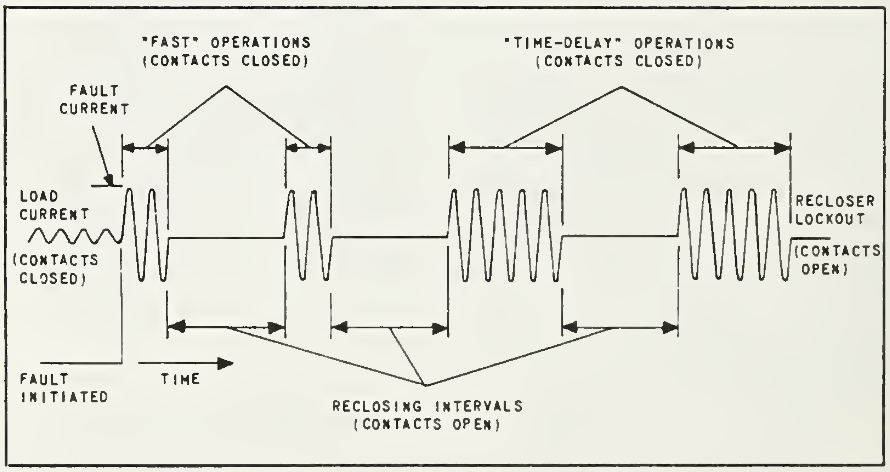


FIGURE V-14
ILLUSTRATION OF RECLOSER OPERATING SEQUENCE
UPON OCCURRENCE OF A PERMANENT FAULT

established by the sequence control device, until the recloser goes to either the lockout or the hold-closed position. If the fault has cleared from the circuit during any open-circuit period, however, the recloser closes and remains closed, and the sequence control device resets so that it is in position for the next sequence of operations. (Refer to Figure V-14.)

a. Manual Tripping

An automatic circuit recloser can be tripped manually by moving the manual-operating handle to the trip position by means of a hookstick, or by moving the control switch to the trip position if the recloser is provided with remote control. If the recloser is provided with a nonreclosing lever, the nonreclosing lever should be pulled down as far as it will go in order to cut out the automatic reclosing before the recloser is manually tripped.

b. Manual Closing

An automatic circuit recloser can be closed manually by moving the manual operating handle to the close position by means of a hookstick or, if the recloser is provided with remote control, by moving the control switch to the close position. If the recloser has a nonreclosing lever, the nonreclosing lever should be pulled down as far as it will go in order to cut out the automatic reclosing before the recloser is closed manually. After the automatic circuit recloser has been successfully closed, the automatic reclosing should be placed in service.

c. Manual Reclosing After Lockout Operation

Many reclosers in service are designed to lock out following a selected sequence of tripping and automatic reclosing operations. The theory behind this type of application is that if a fault is temporary, it will be cleared during the instantaneous operation of the recloser. If the fault is permanent, the recloser goes into time-delay tripping operation and permits sectionalizing devices, such as fuses beyond the recloser, to open and isolate the fault. If a permanent fault should occur between the recloser and the next sectionalizing device out on the line, the recloser then goes to lockout and isolates the fault.

When a recloser appears to be locked out, the operator is always faced with the possibility that the recloser itself may have failed. The following procedure is recommended for reclosing of the recloser after a lockout operation:

(1) Make a careful visual inspection for evidence of distress such as throwing of oil or damaged bushings.

(2) Close the recloser with a hookstick, keeping the hook in the operating ring momentarily so that the recloser can be opened manually in case local trouble or failure becomes evident. If no local trouble develops and the recloser again locks out after going through its proper sequence, it should not be reclosed again until the entire circuit on the load side to all sectionalizing devices has been patrolled and cleared if necessary.

d. Manual Reclosing After Hold-Closed Operation

The recloser that is designed for hold-closed operation performs much the same function as the recloser that goes to lockout. It is normally set to trip instantaneously two times to permit a temporary fault to clear. If the fault is permanent, the recloser latches closed to permit the sectionalizing device nearest the fault to operate and isolate the fault. However, a fuse at the recloser opens the circuit when a permanent fault occurs between the hold-closed recloser and the next sectionalizing device out on the line. The fuse in series with the hold-closed recloser is normally installed on the supply side of the recloser, so that it also protects against electrical failure in the recloser itself. To reclose a recloser after a hold-closed operation, the following procedure is recommended:

(1) Make a careful visual inspection for evidence of distress such as throwing of oil or damaged bushings.

(2) If inspection under (1) indicates that everything is in order, the operator should first open the recloser with a hookstick,

then replace the fuse and close the cutout to check the recloser on the supply side. If everything is in order, he should open the series cutout and close the recloser, then close the series cutout. If there is no local trouble and service is still not restored, then the load side to all sectionalizing devices should be patrolled to determine the cause of the tripout.

e. Load Pickup

The inrush current experienced in closing a recloser after a lockout operation may occasionally introduce some difficulties in getting the recloser to latch closed. The highest inrush current can originate from automatic starting motors or magnetizing current of transformers; however, these types of inrush currents are normally short lived (in the order of three to thirty cycles). Some makes of reclosers may operate on the instantaneous trip due to this inrush current and may have to open and automatically reclose until the sequence of operation comes to the time-delay trip, before the recloser will stay closed. Other makes of reclosers, when reclosed after lockout, do not operate on the instantaneous trip, but have one time-delay trip operation to lock out, which will normally override the inrush current and pick up the load. A cold-load pick-up accessory is available on electronic controls for three-phase reclosers. This accessory temporarily increases the minimum pick-up current to a sufficient value (usually double) to override the cold-load inrush current and allow the recloser to latch closed. Careful observation will indicate whether failure to hold the load is caused by a fault or by heavy overload. Instant and perhaps violent action would indicate a fault, whereas some delay might mean overload due to inrush current. In the latter case, sectionalizing to drop part of the load, rather than a patrol, may be necessary. In any case, if nothing is found on patrol then sectionalizing is indicated.

6. Maintenance and Inspection

Periodic inspection and maintenance are essential to assure efficient, trouble-free service of an oil circuit recloser. Once an automatic circuit recloser is installed,

it should be placed on a periodic schedule of test and inspection. Such test and inspection should cover timing tests, checking of bushings for cracks and of the tank for oil leakage, as well as recording the counter reading. Internal inspection should include contact maintenance or replacement, a check of all gears, linkages, timing devices, test of the oil, etc.

7. Mounting

All reclosers, both single phase and three phase, are suitable for mounting on poles and substation structures. Single phase reclosers can be mounted singly or in clusters. Three phase reclosers have mounting frames that are suitable for base mounting, pad-mount enclosure installation, or modification for pole or substation structure mounting.

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2. ANSI Standard C37.60, "Automatic Circuit Reclosers for Alternating-Current Systems"

3. ANSI Standard C37.61 "Guide for the Application, Operation and Maintenance of Automatic Circuit Reclosers"

4. "Economic Feeder Protection with Automatic Circuit Reclosers," D. R. Shapleigh, The Line, 76/3, p 17

APPENDIX

TO

AUTOMATIC CIRCUIT RECLOSERS

Table 2A§

Rated Maximum Voltage, Rated Continuous Current, Rated Interrupting Current, Rated Impulse Withstand Voltage, and Performance Characteristics of Oil Reclosers

Line No	Nominal System Voltage kV rms	Rated Maximum Voltage kV rms	Rated Impulse Withstand Voltage* kV Crest	Low-Frequency Insulation Level Withstand Test* kV rms: 1-minute Dry	Low-Frequency Insulation Level Withstand Test* kV rms: 10-second Wet	Current Ratings, Amperes: Continuous, 60 Hz	Current Ratings, Amperes: Symmetrical Interrupting† at Rated Maximum Volts	Standard Operating Duty* – Percent of Interrupting Rating 15-20: Minimum X/R	15-20: Number of Unit Operations	45-55: Minimum X/R	45-55: Number of Unit Operations	90-100: Minimum X/R	90-100: Number of Unit Operations	Total Number of Unit Operations
(Col 1)	(Col 2)	(Col 3)	(Col 4)	(Col 5)	(Col 6)	(Col 7)	(Col 8)	(Col 9)	(Col 10)	(Col 11)	(Col 12)	(Col 13)	(Col 14)	(Col 15)
						SINGLE-PHASE RECLOSERS								
1	14.4	15.0	95	35	30	50	1 250	2	40	4	40	8	20	100
2	14.4	15.5	110	50	45	100	2 000	2	32	5	24	10	12	68
3	14.4	15.5	110	50	45	280	4 000	3	32	6	20	12	12	64
4	14.4	15.5	110	50	45	560	8 000	3	28	7	20	14	10	58
5	24.9	27.0	150	60	50	100	2 500	2	32	5	24	12	12	68
6	24.9	27.0	150	60	50	280	4 000	3	32	6	20	13	12	64
7	34.5	38.0	150	70	60	560	8 000	4	28	8	20	15	10	58
						THREE-PHASE RECLOSERS								
8	14.4	15.0	95	35	30	50	1 250	2	40	4	40	8	20	100
9	14.4	15.5	110	50	45	100	2 000	2	32	5	24	10	12	68
10	14.4	15.5	110	50	45	280	4 000	3	32	6	20	12	12	61
11	14.4	15.5	110	50	45	400	4 000	3	32	6	20	12	12	64
12	14.4	15.5	110	50	45	560	8 000	3	28	7	20	14	10	58
13	14.4	15.5	110	50	45	560	16 000	4	16	8	8	16	4	28
14	14.4	15.5	110	50	45	560	16 000	4	28	8	20	16	10	58
15	14.4	15.5	110	50	45	1120	16 000	4	28	8	20	16	10	58
16	24.9	27.0	150	60	50	100	2 500	2	32	5	24	12	12	68
17	24.9	27.0	150	60	50	560	8 000	4	28	8	20	15	10	58
18	24.9	27.0	150	60	50	1120	8 000	4	28	8	20	15	10	58
19	24.9	27.0	150	60	50	560	12 000	4	28	8	20	15	10	58
20	34.5	38.0	150	70	60	400	6 000	4	28	8	24	15	10	62
21	34.5	38.0	200	80	70	560	12 000	4	28	8	20	15	10	58
22	34.5	38.0	200	80	70	1120	12 000	4	28	8	20	15	10	58
23	46.0	48.3	250	105	95	560	10 000	4	28	8	20	15	10	58
24	69.0	72.5	350	160	140	560	8 000	4	28	8	20	16	10	58

*These are performance characteristics specified as test requirements in this standard

†See Table 2B for complete data on rated interrupting currents for reclosers using smaller series coil sizes or reduced minimum trip settings.

§This table is *not* to be used with ANSI C37.61-1973, Guide for the Application, Operation, and Maintenance of Automatic Circuit Reclosers. See Appendix A of this standard for the correct tables to be used with C37.61-1973.

Ref. C37.60

Table 2B[§]

Continuous Current and Interrupting Current Ratings of Oil Reclosers

Continuous Current Rating, Amperes	Interrupting Current Rating in Amperes at Rated Maximum Voltage													
	Single-Phase Series Coil Reclosers							Three-Phase Series Coil Reclosers						
	Recloser Line No							Recloser Line No						
	1	2	3	4	5	6	7	8	9	10	11	12-17	16	20
	Rated Maximum Voltage, kV							Rated Maximum Voltage, kV						
	15.0	15.5	15.5	15.5	27.0	27.0	38.0	15.0	15.5	15.5	15.5	15/27	27.0	34.0
5	125	200	—	—	200	—	—	125	200	—	—	—	200	—
10	250	400	—	—	400	—	—	250	400	—	—	—	400	—
15	375	600	—	—	600	—	—	375	600	—	—	—	600	—
25	625	1000	1500	—	1000	—	—	625	1000	1500	1500	—	1000	1500
35	875	1400	2100	—	1400	—	—	875	1400	2100	2100	—	1400	2100
50	1250	2000	3000	—	2000	3000	—	1250	2000	3000	3000	—	2000	3000
70	—	2000	4000	—	2500	4000	—	—	2000	4000	4000	—	2500	4200
100	—	2000	4000	6000	2500	4000	6000	—	2000	4000	4000	6000	2500	6000
140	—	—	4000	8000	—	4000	8000	—	—	4000	4000	8000	—	6000
200	—	—	4000	8000	—	4000	8000	—	—	4000	4000	8000	—	6000
280	—	—	4000	8000	—	4000	8000	—	—	4000	4000	8000	—	6000
400	—	—	—	8000	—	—	8000	—	—	—	4000	8000	—	6000
560	—	—	—	8000	—	—	8000	—	—	—	—	8000	—	—

Minimum Trip Setting, Amperes	Three-Phase Nonseries Coil Reclosers												
	Recloser Line No												
	11	12	13	14	15	17	18	19	20	21	22	23	24
	Rated Maximum Voltage, kV												
	15.5	15.5	15.5	15.5	15.5	27.0	27.0	27.0	38.0	38.0	38.0	18.3	72.5
100	3000	—	—	—	—	—	—	—	3000	3 000	—	3 000	3000
140	4000	—	—	—	—	—	—	—	4200	4 200	—	4 200	4200
200	4000	6000	6 000	6 000	—	6000	6000	6 000	6000	6 000	6 000	6 000	6000
280	4000	8000	8 400	8 400	—	8000	8000	8 400	6000	8 400	8 400	8 400	8000
400	4000	8000	12 000	12 000	12 000	8000	8000	12 000	6000	12 000	12 000	10 000	8000
560	4000	8000	16 000	16 000	16 000	8000	8000	12 000	6000	12 000	12 000	10 000	8000
800	4000	8000	16 000	16 000	16 000	8000	8000	12 000	6000	12 000	12 000	10 000	8000
1120	—	8000	16 000	16 000	16 000	8000	8000	12 000	—	12 000	12 000	10 000	8000
1600	—		—	—	16 000	—	8000	—	—	—	12 000	—	—
2240	—	—	—	—	16 000	—	8000	—	—	—	12 000	—	—

NOTE: For interrupting current ratings at other than rated voltage, consult the manufacturer. The interrupting current ratings of reclosers are not generally on a constant kVA basis.

[§] This table is *not* to be used with ANSI C37.61-1973, Guide for the Application, Operation, and Maintenance of Automatic Circuit Reclosers. See Appendix A of this standard for the correct tables to be used with C37.61-1973.

Ref. C37.60

Table 3A§

Rated Maximum Voltage, Rated Continuous Current, Rated Interrupting Current, Rated Impulse Withstand Voltage, and Performance Characteristics of Reclosers with Vacuum Interrupters

Line No	Nominal System Voltage kV rms	Rated Maximum Voltage kV rms	Rated Impulse Withstand Voltage* kV Crest	Low-Frequency Insulation Level Withstand Test* kV rms: 1-minute Dry	Low-Frequency Insulation Level Withstand Test* kV rms: 10-second Wet	Current Ratings, Amperes: Continuous 60 Hz	Current Ratings, Amperes: Symmetrical Interrupting† at Rated Maximum Volts	Standard Operating Duty* — Percent of Interrupting Rating 15-20: Minimum X/R	15-20: Number of Unit Operations	45-55: Minimum X/R	45-55: Number of Unit Operations	90-100: Minimum X/R	90-100: Number of Unit Operations	Total Number of Unit Operations
(Col 1)	(Col 2)	(Col 3)	(Col 4)	(Col 5)	(Col 6)	(Col 7)	(Col 8)	(Col 9)	(Col 10)	(Col 11)	(Col 12)	(Col 13)	(Col 14)	(Col 15)
						SINGLE-PHASE RECLOSERS								
1	14.4	15.5	110	50	45	200	2 000	2	52	5	68	10	18	138
						THREE-PHASE RECLOSERS								
2	14.4	15.5	110	50	45	200	2 000	2	52	5	68	10	18	138
3	14.4	15.5	110	50	45	400	6 000	3	48	7	60	14	16	124
4	14.4	15.5	110	50	45	560	12 000	4	44	8	56	15	16	116
5‡	14.4	15.5	110	50	45	800	12 000	4	44	8	56	15	16	116
6	14.4	15.5	110	50	45	560	16 000	4	44	8	52	16	16	112
7‡	14.4	15.5	110	50	45	800	16 000	4	44	8	52	16	16	112
8‡	14.4	15.5	110	50	45	1120	16 000	4	44	8	52	16	16	112

*These are performance characteristics specified as test requirements in this standard.

†See Table 3B for complete data on rated interrupting currents for reclosers using smaller series coil sizes or reduced minimum trip settings.

‡These lines have been approved as Suggested Standard for Future Design.

§This table is *not* to be used with ANSI C37.61-1973, Guide for the Application, Operation, and Maintenance of Automatic Circuit Reclosers. See Appendix A of this standard for the correct tables to be used with C37.61-1973.

NOTE. The standard operating duty represents half life as measured by contact erosion. Refer to the manufacturer's method for determining permissible contact erosion.

Ref. C37.60

Table 3B§

Continuous Current and Interrupting Current Ratings of Reclosers with Vacuum Interrupters

Continuous Current Rating Amperes	Interrupting Current Rating in Amperes at Rated Maximum Voltage: Single-Phase Series Coil Reclosers, Recloser Line No 1, Rated Maximum Voltage, kV 15.5	Interrupting Current Rating in Amperes at Rated Maximum Voltage: Three-Phase Series Coil Reclosers, Recloser Line No 2, Rated Maximum Voltage, kV 15.5
5	200	200
10	400	400
15	600	600
25	1000	1000
35	1400	1400
50	2000	2000
70	2000	2000
100	2000	2000
140	2000	2000
200	2000	2000

Minimum Trip Setting Amperes	Three Phase Nonseries Coil Reclosers					
	Recloser Line No					
	3	4	5	6	7	8
	Rated Maximum Voltage, kV					
	15.5	15.5	15.5	15.5	15.5	15.5
100	3000	3 000	3 000	3 000		
140	4200	4 200	4 200	4 200		
200	6000	6 000	6 000	6 000		
280	6000	8 400	8 400	8 400		
400	6000	12 000	12 000	12 000	12 000	12 000
560	6000	12 000	12 000	16 000	16 000	16 000
800	6000	12 000	12 000	16 000	16 000	16 000
1120		12 000	12 000	16 000	16 000	16 000
1600			12 000		16 000	16 000
2240					16 000	

NOTE: For interrupting current ratings at other than rated voltage, consult the manufacturer. The interrupting current ratings of reclosers are not generally on a constant kVA basis.

§ This table is *not* to be used with ANSI C37.61-1973, Guide for the Application, Operation, and Maintenance of Automatic Circuit Reclosers. See Appendix A of this standard for the correct tables t›be used with C37.61-1973.

Ref. C37.60

J. INSTRUMENT TRANSFORMERS

1. General

This section applies to current and voltage instrument transformers of types generally used in the measurement of electricity and in the control of equipment associated with the transmission and distribution of alternating current.

The primary function of an instrument transformer is stated in the standard definition given in ANSI C57.13, which reads: "An instrument transformer is a transformer that is intended to reproduce in its secondary circuit, in a definite and known proportion, the current or voltage of its primary circuit with the phase relations substantially preserved."

Instrument transformers also provide insulation between the primary and secondary circuits, and thus simplify the construction of measuring devices and provide safety for personnel using those devices.

Occasionally, instrument transformers serve another duty as bus supports, especially at the higher voltages where costs of extra bus supports become significant. The manufacturer should always be consulted in such applications to determine what externally applied forces his product can withstand.

Sometimes, an instrument voltage transformer is used for supplying power, rather than for measurement. In such situations, it is usually possible to place burdens higher than the volt-ampere rating on the secondary circuit without excessive heating and consequent shortening of life. The limit of such burden is known as the Thermal Burden Rating, i.e., "The volt-ampere output that the transformer will supply continuously at rated secondary voltage without causing the specified temperature limits to be exceeded." Good accuracy of transformation will not be maintained for this type of use.

The primary national standard applicable to current and voltage instrument transformers is ANSI C57.13, "Requirements for Instrument Transformers." This standard covers all important aspects, including: Terminology, General Requirements, Ratings, Burdens, Accuracy, Construction and Test Code.

2. Service Conditions

The standard ratings of instrument transformers are based on operation under either or both the following ambient temperature situations, provided the altitude does not exceed 1000 meters (3300 feet):

a. Temperature

The temperature of the cooling air (ambient temperature) does not exceed 40°C (104°F), and the average temperature of the cooling air for any 24 hour period does not exceed 30°C. Note: Instrument transformers designed for 30°C transformer ambient temperature may be applied in ambient temperatures over a range from 30°C to 55°C (86°F to 130°F) by modifying the loading.

The ambient temperature of the cooling air on the inside of enclosed switchgear does not exceed 55°C. See ANSI Standard C37.20, "Switchgear Assemblies and Metal-Enclosed Bus," and NEMA Standard No. SG/5-50, "Power Switchgear Assemblies," for further information.

Instrument transformers used at higher ambient temperatures or at higher altitudes than specified above require special attention to the effects on performance.

Table 4 (see Appendix) of ANSI C57.13 shows the maximum allowable average temperature of cooling air at various altitudes above 1000 meters (3300 feet) in order for the rated burden or current to be used without exceeding the temperature rise limits in Table 3 (see Appendix) of ANSI C57.13. The alternative to reduced ambient temperatures is to operate current transformers at reduced currents (0.3 percent for each 100 meters (330 feet)) above 1000 meters. For alternative VT operation, consult the manufacturer.

b. Altitude

Table 2 (see Appendix) of ANSI C57.13 shows the altitude correction factors to be used to account for the adverse effect of decreased air density on the insulation withstand capability. These correction factors modify the standard insulation classes shown in Table 1 (see Appendix) of ANSI C57.13. A higher standard BIL may be required at high altitudes in order to obtain the insulation required for the voltage used.

3. Accuracy

To be a useful part of a measurement system, instrument transformers must change the magnitude of the voltage or current that is being measured without introducing any unknown errors of measurement into the system. Their accuracy of transformation must, therefore, be either a known value so that the errors can be included in the computation of the overall measurement, or the errors must be within the limits of a specified small value so they may be disregarded.

The accuracy obtainable with an instrument transformer depends on its design, circuit conditions and the burden imposed on the secondary, and is measured in terms of its true value and phase angle under specified operating conditions.

For metering applications, ratio and phase angle data are usually determined experimentally for both current and voltage transformers because of the stringent accuracy requirements. For relaying applications, ratio data may be determined experimentally or may be computed, because a wider range of values is acceptable. The determination of phase angle is unnecessary for most relay applications.

4. Secondary Burdens

"Burden for an instrument transformer is that property of the circuit connected to the secondary winding that determines the active and reactive power at the secondary terminals.

The burden is expressed either as total ohms impedance with the effective resistance and reactive components, or as the total volt-amperes and power factor at the specified value of current or voltage, and frequency."

The burden on the secondary circuit of an instrument transformer affects the accuracy of the device. Accordingly, the burdens of the various meters and other instruments in the secondary must be known. This information is usually obtained from data sheets issued by the manufacturers.

For many purposes, such as when the burdens are known to be well within the rated burden capability of the transformer, or when accuracy is not a concern, it is sufficient

to add arithmetically the volt-ampere burden of the individual devices. If the burden is expressed as an impedance value, the volt-ampere burden can be calculated from the relationship

$$VA = E^2/Z_b$$

where: E is the voltage drop across the burden and

Z_b is the burden impedance.

For more accurate purposes, and when the actual burdens approach the limits of the burden rating, the total burden should be determined by taking individual burden power factors into account.

5. Transformer Correction Factor

The transformer correction factor (TCF) for a current or voltage transformer is the ratio correction factor (RCF) multiplied by the phase angle correction factor for a specified primary circuit power factor.

a. Ratio Correction Factor

The ratio correction factor is the ratio of the true ratio to the marked ratio.

b. Phase Angle Correction Factor

The phase angle correction factor is the ratio of the true power factor to the measured power factor. It is a function of both the phase angles of the instrument transformers and the power factor of the primary circuit being measured.

The phase angle correction factor corrects for the phase displacement of the secondary current or voltage, or both, due to the instrument transformer phase angles.

Phase angle of an instrument transformer is the phase displacement, in minutes, between the primary and secondary values.

6. Current Transformers

A current transformer is an instrument transformer intended to have its primary winding connected in series with the conductor carrying the current to be measured or controlled. The ratio of primary to secondary current is roughly inversely proportional to the ratio of primary to secondary turns and is usually arranged to produce five amperes in the secondary when rated current is flowing in the primary.

a. Types

(1) A bar-type current transformer is one that has a fixed, insulated straight conductor in the form of a bar, rod, or tube that is a single primary turn passing through the magnetic circuit and that is assembled to the secondary core and winding.

(2) A bushing-type current transformer is one that has a round core and a secondary winding insulated from and permanently assembled on the core but has no primary winding nor insulation for a primary winding. This type of current transformer is for use with a fully insulated conductor as the primary winding.

(3) A double-secondary current transformer is one that has secondary coils each on a separate magnetic circuit with both magnetic circuits excited by the same primary winding.

Multiple-secondary (three or more) current transformers are also manufactured.

(4) A multi-ratio current transformer is one from which more than one ratio can be obtained by the use of taps on the secondary winding.

(5) A window-type current transformer is one that has a secondary winding insulated from and permanently assembled on the core, but has no primary winding as an integral part of the structure. Complete or partial insulation is provided for a primary winding in the window through which one or more turns of the line conductor can be threaded to provide the primary winding.

(6) A wound-type current transformer is one that has a fixed primary winding mechanically encircling the core; it may have one or more primary turns. The primary and secondary windings are completely insulated and permanently assembled on the core as an integral structure.

(7) Other types are available in addition to those listed. Descriptions can be found in manufacturers' literature.

b. Ratings (ANSI C57.13)

(1) Insulation classes, related basic impulse insulation levels (BIL), and nominal system voltages are shown in Table 6 (see Appendix).

(2) Current ratings are shown in Table 7 (for other than bushing type) and Table 8 (multi-ratio bushing type). Both Tables 7 and 8 are included in the Appendix.

(3) Standard burdens for current transformers are shown in Table 9 (see Appendix). The first three are burdens for which metering accuracy classes have been assigned, and the last four are for relay accuracy.

(4) Metering accuracy ratings (or classes) are based on the requirement that the transformer correction factor (TCF) shall be within specified limits when the power factor (lag) of the metered load has any value from 0.6 to 1.0 at a specified standard burden, at 100 percent of rated primary current and at the current corresponding to the continuous-thermal-current rating factor.

Table 10 (see Appendix) lists the accuracy classes and corresponding limits for transformer correction factors for current transformers for metering.

For example, the accuracy rating of a current transformer might be 0.3B-0.1 and 0.2 or 0.6B-0.5. The accuracy classes that represent the percent deviation (maximum and minimum) from the rated current, are 0.3 and 0.6 for these examples. The standard burdens, with the characteristics

shown by Table 9 (see Appendix), are 0.1, 0.2 and 0.5 for these examples.

(5) Relay accuracy ratings (or classes) are designated by two symbols, C or T, which describe the capability of the transformer as follows:

   (a) C means the transformer ratio can be calculated according to ANSI C37.13, Paragraph 6.1.

   (b) T means the ratio must be determined by test.

   (c) The secondary terminal voltage rating is the voltage that the transformer will deliver to a standard burden listed in Table 9 at 20 times normal secondary current (and also at any current from one to 20 times rated current at any lesser burden) without exceeding ten percent ratio error.

   For example, relay accuracy class C400 means that the ratio can be calculated and that the ratio error will not exceed ten percent at any current from one to 20 times normal secondary current if the burden does not exceed 4.0 ohms (4.0 ohms X 5 amperes X 20 times normal current equals 400 volts).

   Standard secondary terminal voltage ratings are 10, 20, 50, 100, 200, 400 and 800 volts.

(6) Continuous-thermal-current rating factors shall be 1.0, 1.33, 1.5 or 2.0, based on 30°C ambient in accordance with ANSI C57.13. The C-T-C-Rating Factor is the specified factor by which the primary current of a current transformer can be multiplied to obtain the maximum primary current that can be carried continuously without exceeding the limiting temperature rise from 30°C ambient temperature.

(7) Short-time current ratings (mechanical and thermal) are described in ANSI C57.13, Paragraph 4.6.

c. Open-Circuit Secondary Voltage

Dangerously high voltages (over 3500 volts for Class 1) can exist at the open circuit secondary of current transformers, and appropriate measures shall be taken for safety and insulation withstand capability.

d. Application Data Required For Metering Service

(1) Typical ratio correction factor and phase angle curves for the standard burdens for which accuracy ratings are assigned.

(2) Mechanical and thermal, short time ratings.

e. Application Data Required For Relaying Service

(1) Relaying accuracy classification

(2) Mechanical and thermal, short time ratings

(3) Resistance of secondary winding so as to determine value for each published ratio.

(4) For Class C transformers, typical excitation curves

(5) For Class T transformers, typical overcurrent ratio curves.

7. Voltage Transformers

A voltage transformer is an instrument transformer intended to have its primary winding connected in shunt with a power supply circuit, the voltage of which is to be measured or controlled.

a. Types

(1) A cascade-type voltage transformer is a single high voltage line terminal voltage transformer with the primary winding distributed on several cores with the cores electromagnetically coupled by coupling windings and the secondary winding on the core at the neutral end of the high voltage winding. Each core of this type of transformer is insulated from the other cores

and is maintained at a fixed potential with respect to ground and the line to ground voltage.

(2) A double-secondary voltage transformer is one that has two secondary windings on the same magnetic circuit insulated from each other and the primary. Either or both of the secondary windings may be used for measurements or control.

(3) A grounded-neutral, terminal type voltage transformer is one that has the neutral end of the high voltage winding connected to the case or mounting base.

(4) A insulated-neutral, terminal voltage transformer is one that has the neutral end of the high voltage winding insulated from the case or base and connected to a terminal that provides insulation for a lower voltage insulation class than required for the rated insulation class of the transformer.

(5) A single high voltage line, terminal voltage transformer is one that has the line end of the primary winding connected to a terminal insulated from ground for the rated insulation class. The neutral end of the primary winding may be connected as in (3) or (4) preceding.

(6) A two high voltage line, terminal voltage transformer is one that has both ends of the high voltage winding connected to separate terminals that are insulated from each other, and from other parts of the transformer, for the rated insulation class of the transformer.

b. Ratings (ANSI C57.13)

(1) Insulation classes, related basic impulse insulation levels (BILs), primary voltage ratings and marked ratios are shown in Tables 12 and 12A (see Appendix).

The standard voltage transformers listed in the tables are divided into Groups 1, 2 and 3.

Group 1: Designed for line to line, line to ground, or line to neutral service.

Group 2: Designed for line to line service, but may be used line to ground or line to neutral at a voltage across the winding equal to the rated line to line voltage divided by 3. This restriction is due to insulation limitations from line to ground.

Group 3: Designed for line to ground service only and having two secondaries.

Typical primary connections for the three groups of voltage transformers are shown in Figure 7 (see Appendix) of ANSI C57.13.

(2) A voltage transformer shall be assigned an accuracy class rating (see ANSI C57.13) for each of the standard burdens for which it is designed. For example, an accuracy rating may be 0.3W and 0.3X, 0.6Y, 1.2Z. 0.3, 0.6 and 1.2 represent the percent deviation (maximum and minimum) from the rated voltage. W, X, Y and Z are standard burdens (one other is ZZ).

Standard burdens for voltage transformers for accuracy rating purposes are given in Table 13 (see Appendix). The burdens are expressed in volt-amperes at a specified power factor at either 120 or 69.3 volts.

Accuracy classes are based on the requirement that the transformer correction factor (TCF) shall be within specified limits when the power factor of the metered load has any value from 0.6 lag to 1.0, from zero burden to the specified standard burden and at any voltage from 90 to 110 percent of the rated transformer voltage. Accuracy classes and corresponding limits of TCF are shown in Table 14 (see Appendix).

(3) The thermal burden rating of a voltage transformer shall be specified in terms of the maximum burden that the transformer can carry at rated secondary voltage without exceeding the temperature rise, above 30°C (86°F) ambient, permitted by Table 3.

(4) Application Data

(a) Typical ratio and phase angle curves for rated primary voltage, plotted for the standard burdens and for the same numerical burdens with unity power factor, from zero burden to the maximum standard burden volt-amperes of the transformer.

(b) Accuracy ratings for all standard burdens up to and including the maximum standard burden rating of the transformer.

(c) Thermal burden rating.

8. Tests

Section 6, Test Code, of ANSI C57.13 describes the usual program of testing an instrument transformer. Although these tests are usually performed only in the factory, there may be occasions when the user will perform some of them in his own testing facility or in the field. It is recommended that Section 6 be consulted for guidance and precautions whenever such tests are planned.

APPENDIX

TO

INSTRUMENT TRANSFORMERS

Table 1
Insulation Classes and Dielectric Tests*

Insulation Class kV	Low-Frequency Test kV	BIL and Full Wave kV Crest	Chopped Wave kV Crest	Chopped Wave Min Time to Flashover, μs
0.6	4	10	12	—
1.2	10	30	36	1
2.5	15	45	54	1.5
5.0	19†	60	69	1.5
8.7	26	75	88	1.6
15L	34	95	110	1.8
15H	34	110	130	2
18	40	125	145	2.25
25	50	150	175	3
34.5	70	200	230	3
46	95	250	290	3
69	140	350	400	3
92	185	450	520	3
115	230	550	630	3
138	275	650	750	3
161	325	750	865	3
180	360	825	950	3
196	395	900	1,035	3
215	430	975	1,120	3
230	460	1,050	1,210	3
260	520	1,175	1,350	3
287	575	1,300	1,500	3
315	630	1,425	1,640	3
345	690	1,550	1,780	3
375	750	1,675	1,925	3
400	800	1,800	2,070	3
430	860	1,925	2,220	3
460	920	2,050	2,360	3
490	980	2,175	2,500	3
520	1,040	2,300	2,650	3
545	1,090	2,425	2,800	3

*This table applies to transformers used as separate pieces of equipment. Where the transformers are component parts of other equipment, such as switchgear, the dielectric tests may be specified in accordance with the applicable USA Standards for the other equipment.

†Neutral end of outdoor potential transformer intended for operation connected to ground shall withstand a 19 kV 60 Hz test for one minute.

Ref. C57.13

Table 2
Altitude Correction Factors for Insulation Classes

Altitude Feet	Altitude Meters	Altitude Correction Factor for Insulation Class
3,300	1,000	1.00
4,000	1,200	0.98
5,000	1,500	0.95
6,000	1,800	0.92
7,000	2,100	0.89
8,000	2,400	0.86
9,000	2,700	0.83
10,000	3,000	0.80
12,000	3,600	0.75
14,000	4,200	0.70
15,000	4,500	0.67

*Altitude of 15,000 feet is considered a maximum for instrument transformers.

Table 3
Limits of Temperature Rise

Type of Instrument Transformer	30°C Ambient: Winding Temperature Rise	30°C Ambient: Hottest-Spot Winding Temperature Rise	55°C Ambient: Winding Temperature Rise	55°C Ambient: Hottest-Spot Winding Temperature Rise
55°C Rise Oil-Immersed	55°C	65°C	30°C	40°C
55°C Rise Dry-Type	55°C	65°C	30°C	40°C
80°C Rise Dry-Type	80°C	110°C	55°C	85°C

NOTES:

(1) Instrument transformers with specified temperature rise shall have an insulation system which has been proven by experience, general acceptance, or accepted tests.

(2) The winding temperature rise shall be determined by the resistance method.

(3) Metallic parts in contact with or adjacent to insulation shall not attain a temperature in excess of that allowed for the hottest spot of the conductor adjacent to that insulation. Other metallic parts shall not attain excessive temperature rises.

(4) Where apparatus employs a sealed-tank oil preservation system, the temperature rise of the insulating oil shall not exceed 55°C for 30°C ambient nor exceed 30°C for 55°C ambient when measured near the top of the main apparatus tank.

Table 4
Maximum Allowable Average Temperature of Cooling Air for Carrying Rated Burden or Current*

Method of Cooling	3,300 ft (1,000 m)	6,600 ft (2,000 m)	9,900 ft (3,000 m)	13,200 ft (4,000 m)
Oil-Immersed Self-Cooled	30°C	28°C	25°C	23°C
Dry-Type Self-Cooled				
55°C Rise	30°C	27°C	24°C	21°C
80°C Rise	30°C	26°C	22°C	18°C

*See 3.1.1.1 for explanation of average temperature.

Ref. C57.13

Table 6
Insulation Classes for Current Transformers

Insulation Class kV	Maximum Line-to-Neutral Voltage* kV	Nominal System Voltage† kV	Basic Impulse Insulation Level kV
0.6	0.380	—	10
1.2	0.762	—	30
2.5	1.59	—	45
5.0	3.18	—	60
8.7	5.52	—	75
15L	9.53	—	95
15H	9.53	—	110
25	15.9	—	150
34.5	21.9	—	200
46	29.2	—	250
69	43.8	—	350
92	—	92	450
115	—	115	550
138	—	138	650
161	—	161	750
196	—	196	900
230	—	230	1,050
287	—	287	1,300

*The voltage values in this column are 110 percent of the line-to-neutral voltage of the system on which the transformer is used.

†The choice of insulation class for current transformers is a function of the protective level of the system at the transformer, and other characteristics of the transformer such as continuous line-to-neutral voltage.

Table 7
Current Transformer Ratings Other Than Bushing Type

Current Ratings, Amperes			
Single Ratio		Double Ratio with Series-Parallel Primary Windings	Double Ratio with Taps in Secondary Winding
10:5	800:5	25 x 50:5	25/50:5
15:5	1,200:5	50 x 100:5	50/100:5
25:5	1,500:5	100 x 200:5	100/200:5
40:5	2,000:5	200 x 400:5	200/400:5
50:5	3,000:5	400 x 800:5	300/600:5
75:5	4,000:5	600 x 1,200:5	400/800:5
100:5	5,000:5	1,000 x 2,000:5	600/1,200:5
200:5	6,000:5	2,000 x 4,000:5	1,000/2,000:5
300:5	8,000:5		1,500/3,000:5
400:5	12,000:5		2,000/4,000:5
600:5			

Ref. C57.13

Table 8
Current Transformer Ratings, Multi-Ratio Bushing Type

Current Ratings Amperes	Secondary Taps	Current Ratings Amperes	Secondary Taps
600:5		2,000:5	
50:5	X2 - X3	300:5	X3 - X4
100:5	X1 - X2	400:5	X1 - X2
150:5	X1 - X3	500:5	X4 - X5
200:5	X4 - X5	800:5	X2 - X3
250:5	X3 - X4	1,100:5	X2 - X4
300:5	X2 - X4	1,200:5	X1 - X3
400:5	X1 - X4	1,500:5	X1 - X4
450:5	X3 - X5	1,600:5	X2 - X5
500:5	X2 - X5	2,000:5	X1 - X5
600:5	X1 - X5	3,000:5	
1,200:5		1,500:5	X2 - X3
100:5	X2 - X3	2,000:5	X2 - X4
200:5	X1 - X2	3,000:5	X1 - X4
300:5	X1 - X3	4,000:5	
400:5	X4 - X5	2,000:5	X1 - X2
500:5	X3 - X4	3,000:5	X1 - X3
600:5	X2 - X4	4,000:5	X1 - X4
800:5	X1 - X4	5,000:5	
900:5	X3 - X5	3,000:5	X1 - X2
1,000:5	X2 - X5	4,000:5	X1 - X3
1,200:5	X1 - X5	5,000:5	X1 - X4

Ref. C57.13

Table 9
Standard Burdens for Current Transformers

Standard Burden Designation	Characteristics: Resistance Ohms	Characteristics: Inductance Millihenrys	Characteristics for 60 Hertz and 5 Ampere Secondary Current: Impedance Ohms	Volt-Amperes	Power Factor
B-0.1	0.09	0.116	0.1	2.5	0.9
B-0.2	0.18	0.232	0.2	5.0	0.9
B-0.5	0.45	0.580	0.5	12.5	0.9
B-1	0.5	2.3	1.0	25	0.5
B-2	1.0	4.6	2.0	50	0.5
B-4	2.0	9.2	4.0	100	0.5
B-8	4.0	18.4	8.0	200	0.5

Table 10
Accuracy Classes and Corresponding Limits of Transformer Correction Factors for Current Transformers for Metering*

Metering Accuracy Classes	Limits of Transformer Correction Factor: 100% Rated Current† Min	100% Rated Current† Max	10% Rated Current Min	10% Rated Current Max	Limits of Power Factor (Lag) of Metered Power Load
0.3	0.997	1.003	0.994	1.006	0.6 - 1.0
0.6	0.994	1.006	0.988	1.012	0.6 - 1.0
1.2	0.988	1.012	0.976	1.024	0.6 - 1.0

*See Figs. 1, 2, and 3.
†These limits also apply at the maximum continuous-thermal-current rating factor.

Ref. C57.13

Table 12
Insulation Classes, Basic Impulse Insulation Levels, Primary Voltage Ratings, and Marked Ratios for Potential Transformers

Insulation Class (kV)	Basic Impulse Insulation Level (kV Crest)	Primary Voltage Rating Rated Voltage Line-to-Line (Volts)	Marked Ratio
Group 1: 0.6 to 15 kV, Full Insulation, Y - Voltage Limit Equals $\sqrt{3}$ Times Δ - Voltage Limit			
0.6	10	120/208Y	1:1
0.6	10	240/416Y	2:1
0.6	10	300/520Y	2.5:1
1.2	30	120/208Y	1:1
1.2	30	240/416Y	2:1
1.2	30	300/520Y	2.5:1
1.2	30	480/832Y	4:1
1.2	30	600/1,040Y	5:1
5.0	60	2,400/4,150Y	20:1
8.7	75	4,200/7,280Y	35:1
8.7	75	4,800/8,320Y	40:1
15L	95	7,200/12,470Y	60:1
15L	95	8,400/14,560Y	70:1
15H	110	7,200/12,470Y	60:1
15H	110	8,400/14,560Y	70:1
Group 2: 0.6 to 161 kV, Full Insulation, Y - Voltage Limit Equals Δ - Voltage Limit			
0.6	10	120/120Y	1:1
0.6	10	240/240Y	2:1
0.6	10	300/300Y	2.5:1
0.6	10	480/480Y	4:1
0.6	10	600/600Y	5:1
2.5	45	2,400/2,400Y	20:1
5.0	60	4,800/4,800Y	40:1
8.7	75	7,200/7,200Y	60:1
15L	95	12,000/12,000Y	100:1
15L	95	14,400/14,400Y	120:1
15H	110	12,000/12,000Y	100:1
15H	110	14,400/14,400Y	120:1
25	150	24,000/24,000Y	200:1
34.5	200	34,500/34,500Y	300:1
46	250	46,000/46,000Y	400:1
69	350	69,000/69,000Y	600:1
92	450	92,000/92,000Y	800:1
115	550	115,000/115,000Y	1,000:1
138	650	138,000/138,000Y	1,200:1
161	750	161,000/161,000Y	1,400:1

Pef. C57.13

Table 12A
Group 3 Potential Transformers with Reduced Insulation at Neutral End for Connection Directly to Ground Through an Insulated Terminal

Primary Voltage Rating for Rated Voltage Line-to-Line (Volts)	Marked Ratio
14,400 for 25,000 Grd Y	120 & 200:1
20,125 for 34,500 Grd Y	175 & 300:1
27,600 for 46,000 Grd Y	240 & 400:1
40,250 for 69,000 Grd Y	350 & 600:1
55,200 for 92,000 Grd Y	480 & 800:1
69,000 for 115,000 Grd Y	600 & 1,000:1
80,500 for 138,000 Grd Y	700 & 1,200:1
92,000 for 161,000 Grd Y	800 & 1,400:1
115,000 for 196,000 Grd Y	1,000 & 1,700:1
138,000 for 230,000 Grd Y	1,200 & 2,000:1
172,500 for 287,000 Grd Y	1,500 & 2,500:1
207,000 for 345,000 Grd Y	1,800 & 3,000:1
-	2,500 & 4,500:1

*Primary voltage rating has not been established.

NOTE: For potential transformers in this table which have double ratio achieved by means of a tap in either of the secondary windings, the nonpolarity end of the tapped winding shall be the common lead.

Ref. C57.13

Table 13
Standard Burdens for Potential Transformers

Standard Burdens			Characteristics on 120 Volt Basis			Characteristics on 69.3 Volt Basis		
Designation	Volt-Amperes	Power Factor	Resistance Ohms	Inductance Henrys	Impedance Ohms	Resistance Ohms	Inductance Henrys	Impedance Ohms
W	12.5	0.10	115.2	3.042	1152	38.4	1.014	384
X	25	0.70	403.2	1.092	576	134.4	0.364	192
Y	75	0.85	163.2	0.268	192	54.4	0.0894	64
Z	200	0.85	61.2	0.101	72	20.4	0.0336	24
ZZ	400	0.85	30.6	0.0504	36	10.2	0.0168	12

Table 14
Accuracy Classes and Corresponding Limits of Transformer Correction Factors for Potential Transformers for Metering Service

Metering Accuracy Classes	Limits of Transformer Correction Factors for Range of 90 to 110 Percent Rated Primary Voltage		Limits of Power Factor (Lag) of Metered Power Load
	Min	Max	
0.3	0.997	1.003	0.6 - 1.0
0.6	0.994	1.006	0.6 - 1.0
1.2	0.988	1.012	0.6 - 1.0

Ref. C57.13

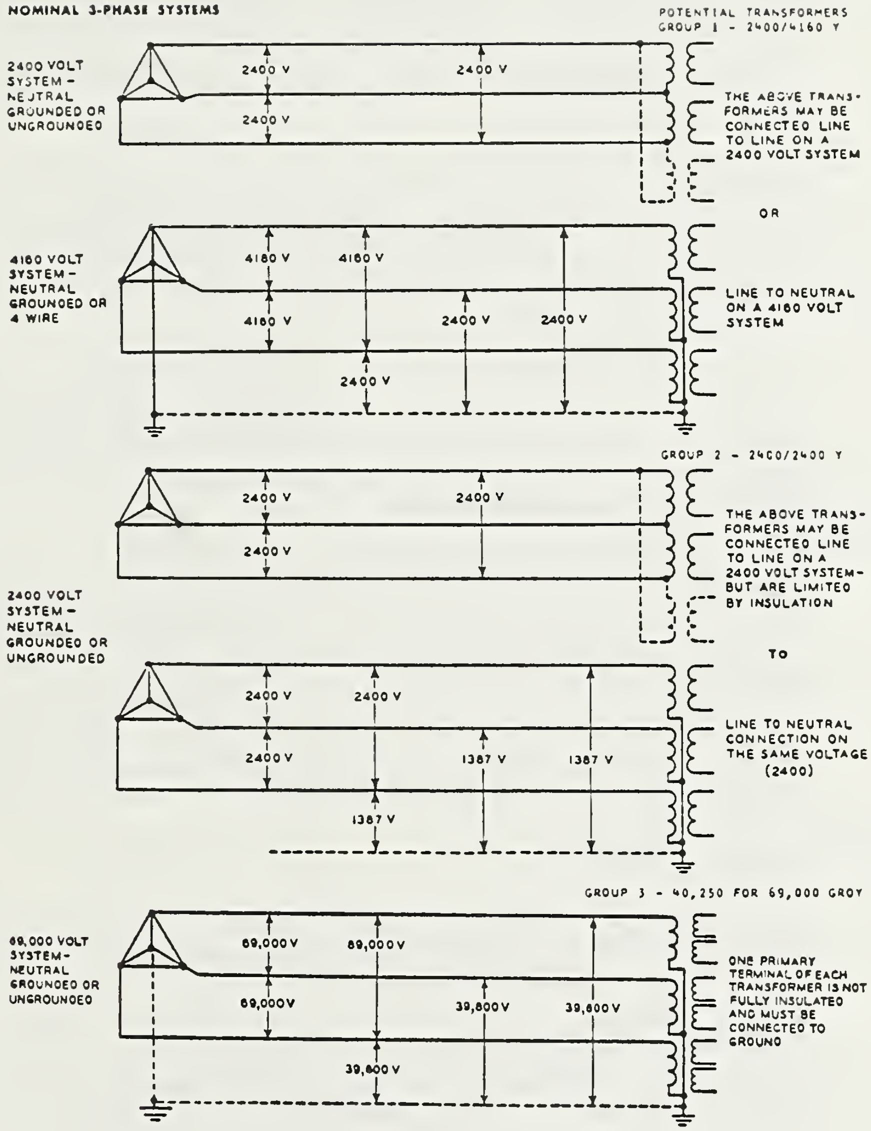


Fig. 7
Typical Primary Connections for Potential Transformers

NOTE for Group 2 The double ratio for the transformers is obtained by two secondary windings to provide the same rated voltage in the secondary from line-to-neutral as from line-to-line.

Ref. C57.13

K. COUPLING CAPACITORS AND COUPLING CAPACITOR VOLTAGE TRANSFORMERS

1. General

This section deals with coupling capacitors and coupling capacitor voltage transformers. Both are single phase devices that utilize one or more capacitor units, usually mounted on a base, to couple phase-to-ground to a high voltage power line.

The base contains various accessories necessary to perform the desired function(s). The primary functions are to couple carrier current communication equipment to a power line and/or to provide low voltage source(s) for operating relays and instruments.

The ANSI Standard applicable to the power line coupling capacitors is ANSI C93.1, "Requirements for Power Line Coupling Capacitors." This standard covers such items as definitions, service conditions, ratings, testing and manufacturing requirements.

The National Electrical Manufacturers Association standard publication No. SG-11, "Coupling Capacitors, Coupling Capacitor Potential Devices and Line Traps," covers information similar to that covered by ANSI C93.1, plus additional information on capacitance ratings, coupling capacitor potential (called "voltage" in latest standards) devices and line traps. In areas where conflict may exist between the two standards, ANSI C93.1 should override.

2. Coupling Capacitors

Coupling capacitors (CCs) are devices used for coupling carrier current communication equipment to a high voltage power line. The base contains the carrier current accessories required for connection directly to a coaxial cable running to the power line carrier equipment located separately from the CC. A coupling capacitor will usually consist of the following equipment and accessories:

a. One or More Stacked, Oil-Filled Capacitor Units

The capacitor elements are enclosed in a sealed porcelain container similar to an insulator and mounted on a supporting base.

b. Drain Coil

The drain coil provides a ground to the 60 Hz frequency but offers high impedance to the carrier frequency.

c. Carrier Grounding Switch and Protective Gap

The grounding switch is used to bypass the drain coil during inspection or maintenance. It is operated externally by means of a switch handle with an eye convenient for switch stick use. It does not interrupt the operation of the high voltage line or, when used, the voltage transformer components. The gap protects the drain coil from excessive voltage surges during normal operation.

d. Lead-in Bushing

A suitable carrier cable is run from the lead-in bushing terminal to the carrier current transmitters and receivers and to other communication equipment.

e. Space Heater

A space heater is primarily used for prevention of condensation.

f. High Voltage Terminal and Ground Terminal

g. Space For a Future Voltage Transformer and Components

Once these components are added, the device is considered to be a coupling capacitor voltage transformer with carrier accessories.

A coupling capacitor used for power line carrier coupling is shown schematically in Fig. A1 (see Appendix) of Appendix to ANSI C93.1. In addition, a wideband high-pass type filter may be included in the base and connected between the other carrier accessories in the base and the coax-cable connection.

3. Coupling Capacitor Voltage Transformers

Coupling capacitor voltage transformers (CCVTs) are devices used for coupling to a power line to provide low voltage(s) for the operation of relays and instruments. Carrier accessories may be included in the base or they may be

added later. An assembly may consist of the following equipment and accessories, however, there is a variety of equipment and accessories available, depending on the requirements of the system.

a. <u>One or More Stacked, Oil-Filled Capacitor Units</u>

A portion of the capacitance in the lower capacitor unit is tapped to provide a voltage proportional to line voltage in accordance with the potential dividing properties of the capacitor string. Such a device is called a coupling capacitor divider. The tapped connection is brought to a terminal in the base, designated as the intermediate-voltage terminal.

b. <u>Main Voltage Transformer</u>

This transformer provides the output voltages desired, usually 66.4 volts and 115 volts.

c. <u>Variable Reactance Transformer</u>

This transformer is provided to adjust the phase angle of the derived voltage.

d. <u>Voltage-Adjusting Transformer</u>

This transformer is provided to adjust the voltage magnitude.

e. <u>Choke Coil</u>

The voltage transformer is connected to the intermediate-voltage terminal through this carrier frequency choke coil. This choke coil isolates the voltage transformer from the capacitor at carrier frequencies.

f. <u>Transformer Grounding Switch</u>

This switch is used to ground the 60 Hz frequency when the voltage device is desired out of service. It does not interrupt the operation of the high voltage line or, when used, the carrier current equipment.

g. <u>Transformer Protective Gap</u>

Provided to protect the voltage transformer from excessive surges from the line during normal operation.

h. <u>Power Factor Correction Capacitor</u>

Used to adjust the power factor of the burden.

i. <u>Space Heater; High Voltage and Ground Terminals</u>

When also used for power line carrier coupling, carrier accessories will be included in the base, generally the same as included in Paragraph 2, Coupling Capacitors.

The above arrangement is shown schematically in Fig. A2 (see Appendix) of Appendix to ANSI C93.1 and in Fig. 3 (see Appendix). Fig. 3 shows several typical arrangements of voltage transformers and associated components located in the base and connected to the intermediate-voltage terminal shown in Fig. A2.

Different manufacturers may use different components and arrangements to obtain the objective of a voltage, representative of line voltage at required accuracy. Sometimes, part of the accessories for adjustment purposes associated with the capacitor voltage transformer are located in a separate cabinet mounted close to the base usually on the same supporting structure.

CAUTION: Never short out the secondary on a capacitor voltage transformer.

4. <u>Service Conditions</u>

a. <u>Temperature</u>

Coupling capacitors are designed for outdoor service at ambient temperatures from -40°C to +45°C (-40°F to +113°F). +45°C is the upper limit for a one hour period. Other limits are +40°C mean over 24 hours and +30°C mean over one year. Consult the manufacturer when temperatures exceed these limits.

b. Altitude

Maximum altitude is 1000 meters (3300 feet). Dielectric strength is decreased at higher altitudes, approximately 5 percent for each 500 meters above 1000 meters.

c. Frequencies

The power frequency is 60 Hz.

The carrier frequency range is 30-300 kHZ.

5. Ratings

The standard voltage ratings of coupling capacitors are given in Table 3 (see Appendix) of ANSI C93.1. This table also includes system voltages; insulation withstand voltage levels for impulse, switching surge and power frequency; and minimum leakage distance of the outside porcelain. Although not shown in Table 3, the rated high-voltage capacitance must also be included in any complete coupling capacitor rating. See Paragraph 6, Capacitance, for information on high voltage capacitance ratings.

Table 3 shows that standard coupling capacitors are rated for line-to-ground service and possess full basic insulation levels (BILs) for each nominal system voltage level at least through 230 kV. The full BIL is due partly to standarization but also in recognition of the fact that they are usually located at line entrances and thus more exposed to incoming surges.

6. Capacitance

CCs and CCVTs are usually classified as "low capacitance," "high capacitance" or "extra-high capacitance," depending on the value of the high-voltage capacitance. The high-voltage capacitance C_1 is the capacitance between the high-voltage and intermediate-voltage terminals. The high-voltage capacitance standard ratings for "low capacitance" and "high-capacitance" devices are defined in NEMA SG-11 Paragraph 3.05. The high-voltage capacitance ratings for "extra-high capacitance" units are approximately three times that of the "high-capacitance" devices. Available ratings are listed in manufacturer's catalogs.

The typical "low-capacitance" device is not suitable for broadband carrier coupling but can be equipped for resonant coupling of one or two carrier channels to a power transmission line. A burden as high as 150 VA may be connected to the device. It is not suitable for revenue metering.

The typical "high-capacitance" unit can be equipped for broadband carrier coupling, and some units can be furnished for one or two frequency carrier coupling. Its burden capability ranges up to 200 VA at 0.8 power factor. It is not suitable for revenue metering, but can be used for supervisory control and data acquisition systems.

The typical "extra-high capacitance" device is particularly applicable on the higher voltage systems, 115 kV and above, where the increased capacitance rating is desired to provide a low impedance path for carrier signals. It is also the only type of CCVT suitable for revenue metering, with an accuracy class of 0.3 for all standard burdens through ZZ. ANSI burdens and accuracy class are discussed under Instrument Transformers. Its burden capability ranges up to 400 VA. The higher capacitance devices are generally more expensive than the lower capacitance devices.

The "extra-high capacitance" CCVT is particularly applicable at high voltage and extra high voltage interconnections between two utilities where revenue metering from the primary transmission line is essential and where broadband coupling is desired between carrier transmitter-receiver equipment and the power line.

The accuracy rating of the typical CCVT will usually apply to the total burden on the device regardless of how that burden is divided among the secondary windings, provided that any burden limit on any winding is not exceeded.

7. Tests

Section 5. of ANSI C93.1 fully describes the various test conditions, routine tests and design tests. Two routine tests that are to be made on each completed capacitor unit (this is an assembly of capacitor elements in a single container with accessible connections) are:

> Capacitance and dissipation factor measurements up to rated maximum voltage and frequency before and after overvoltage tests.

Overvoltage tests, one-minute dry, 60 Hz withstand, see Table 3 in the Appendix.

Dissipation factor is the tangent of the angle delta by which the phase difference between the voltage applied to the capacitor and resulting current deviates from 90 degrees. Usually expressed in percent df.

APPENDIX

TO

COUPLING CAPACITORS

AND

COUPLING CAPACITOR VOLTAGE TRANSFORMERS

Table 3
Voltage Ratings for Coupling Capacitors

Nominal System Voltage (Note 1) (kV)	Power Frequency Minimum Withstand Voltage (kV)		Maximum Voltage System (kV)	Maximum Rated Voltage (Note 2) (kV)	Minimum Leakage Distance (Inches)	Minimum Basic Lightning Impulse Insulation Level (BIL) (kV)	Minimum Basic Switching Impulse Insulation Level (BSL) (kV)
	1 Minute Dry	10 Second Wet					
Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
34.5	85	72	36.2	22	26	200	–
46	110	95	48.3	28	35	250	–
69	165	140	72.5	42	48	350	–
115	265	230	123	70	79	550	–
138	320	275	145	84	92	650	–
161	370	325	170	98	114	750	–
230	525	460	245	140	154	1050	
345*	785	680	362	209	230	1550	975
500*	900	780	550	317	350	1800	1300
735-765*	1200	1050	800	462	510	2425	1675

*These typical values are suggested for future study and investigations.

NOTE 1: These values correspond to the preferred nominal system voltages given in American National Standard Voltage Ratings for Electric Power Systems and Equipment, C84.1-1970, except the 345, 500, and 765 kV ratings.

NOTE 2: These values are the phase-to-ground voltages corresponding to the maximum voltage of the tolerable zone for voltages at substations and on transmission systems given in American National Standard C84.1-1970.

Ref. C93.1

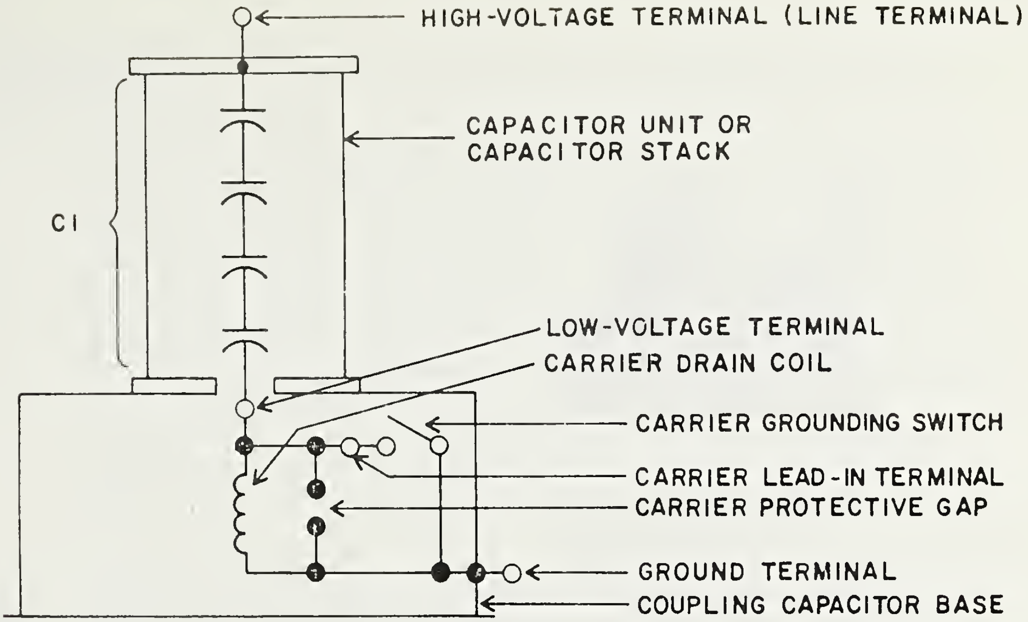


Fig. A1
Coupling Capacitor with Carrier Coupling

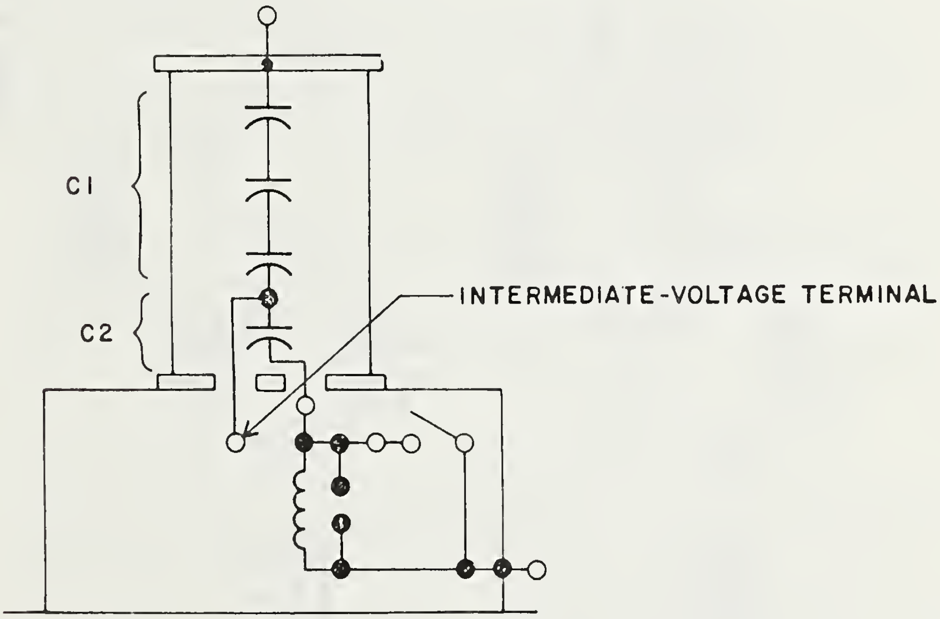
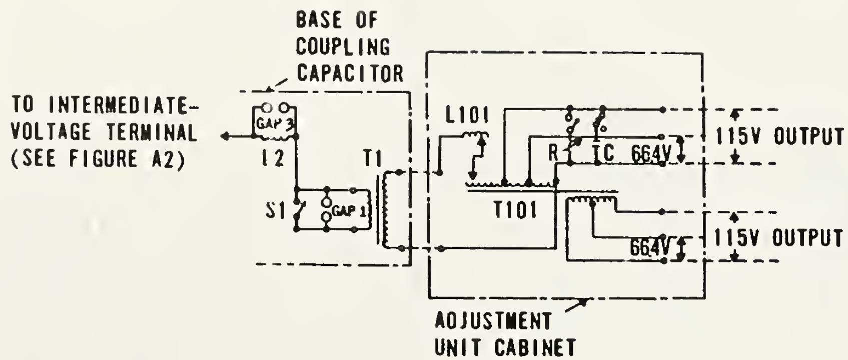
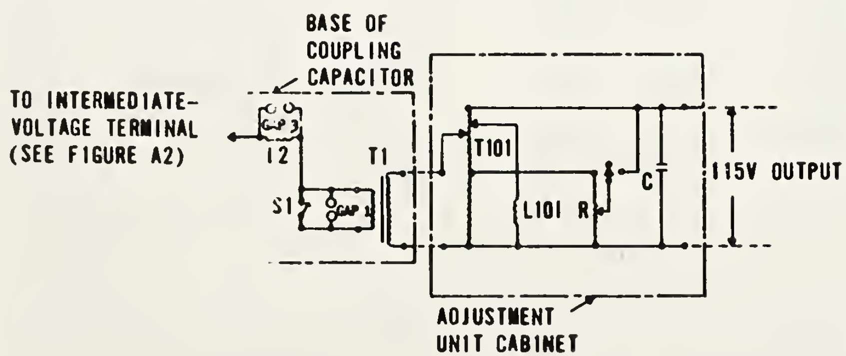


Fig. A2
Capacitor Divider with Carrier Coupling

Ref. C93.1





T1	MAIN POTENTIAL-DEVICE TRANSFORMER
T101	ADJUSTMENT-UNIT TRANSFORMER
R	LOADING RESISTOR
L101	REACTOR
C1	COUPLING CAPACITOR
C2	AUXILIARY CAPACITOR
S1	GROUNDING SWITCH
L1	DRAIN COIL
L2	CHOKE COIL

FIGURE V-15

TYPICAL VOLTAGE TRANSFORMER COMPONENTS

L. MOBILE UNITS

1. General

A mobile unit substation or mobile transformer is one in which all of the components are mounted on a highway trailer or rail car. These units may be readily moved from one location to another by a tractor or locomotive. Mobile units are used to provide supplementary service during seasonal and temporary load conditions and as spares for existing installations during periods of outage due to equipment breakdowns or planned maintenance and construction. Their use can permit a higher quality of maintenance, more safely and at less cost, and reduce system investment in overall transformer capacity.

The actual make-up of a mobile unit will depend on factors, such as: the intended scope of application, degree of flexibility and reliability desired, physical size and weight restrictions, safety, and economics. Each user will have to determine the correct blend of these factors for his system.

2. Feasibility

The purchase of a mobile unit should be supported by an economic study proving this method of providing service continuity to be less expensive than other methods (such as individual spare transformers or looped feeder lines) that can provide comparable reliability of service.

The study should consider carefully the kVA capacity and voltages of the substation transformers to be spared by the mobile unit. There is a practical limit to the flexibility that should be attempted in one unit. Two (or more) units may be the best answer on some systems where the variety of substations is great.

The design of many mobile units is restricted by the opposing requirements of larger transformer capacity, higher primary voltages and highway limitations on physical size and weight. Although it is generally desirable to obtain the maximum capacity from the transformer section of a mobile unit, it is the transformer kVA that must be limited in most cases, since, for a given mobile unit, the other components tend to remain the same in size and weight, regardless of kVA.

Since highway restrictions vary from state to state, it is difficult for a manufacturer to adopt a standard design for a mobile unit. Therefore, close coordination should be exercised among the purchaser, the design engineers and the state highway commission(s).

In attempting to meet all of the requirements desired, it is important that all necessary safety clearances between phases and phase-to-ground be maintained in accordance with Chapter IV. Basic insulation levels and surge protection should be selected and coordinated in accordance with good modern practice (see Chapter V Power Transformers and Surge Arresters).

3. <u>Mobile Transformers</u>

This is a transformer, usually three-phase, mounted on a trailer or semi-trailer together with cooling equipment such as oil pump, heat exchanger, fans, etc. It is intended for application in a substation as a spare transformer in place of permanently installed transformers that may have failed or that may be undergoing maintenance. Other uses include provision of extra kVA capacity during temporary heavy load situations.

Switchgear, circuit breakers, or reclosers are not included. It is recommended, however, that both high-voltage and low-voltage surge arresters be mounted either on the transformer or on the trailer, since the transformer, when in use, may be too far from the substation arresters to be protected adequately.

The availability of a mobile three-phase transformer as a spare permits a saving in the purchase of substation transformers. Instead of buying four single-phase transformers in order to have a spare in each substation, a power system can save a substantial part of this cost by buying one three-phase transformer and depending on the mobile unit for a spare. Because of the much higher cost of the mobile unit, this saving can be realized only if the system operates several substations having approximately the same kVA size and compatible voltage requirements.

4. <u>Mobile Substations</u>

A mobile substation may include, in addition to the transformer, air switches, surge arresters, high-voltage fuses, reclosers or breakers, voltage regulating equipment,

control power and instrument transformers, meters and relays, control cabinet and various accessories, to permit it to operate as a complete substation independent of any permanent ground-mounted equipment. Thus, it can be used not only as a spare transformer but can replace an entire substation that has been damaged or can serve as a temporary substation in a new location until a permanent substation can be built.

One limitation of a mobile substation is the number of outgoing distribution circuits that can be provided conveniently. Mobile substations can generally provide only one or two distribution circuits without an auxiliary switching structure or other supplementary equipment mounted on a separate trailer.

5. Phase Rotation Indicators

Three-phase units should be equipped with suitable phase rotation indicators or relays to ensure that power supplied to distribution circuits has the same phase rotation as that supplied from the permanent substation. Relays should also be provided to prevent reverse rotation of the fan and pump motors. Reversing switches should be added to these motors so that they can adapt to the phase rotation of the power supply.

6. Other Considerations

a. Impedance

To reduce size and weight, the transformers in mobile units are usually designed for forced-cooled operation with higher impedances based on the forced-cooled kVA rating than are normal for most self-cooled power transformers. These impedances sometimes are as high as 12 to 15 percent. This usually makes it impractical to operate a mobile unit in parallel with a ground-mounted unit unless a sacrifice in total kVA available from the paralleled units is acceptable.

A general rule is that, for proper division of load, the impedances of transformers connected in parallel should be as close as possible and, in no case, differ by more than 7.5 percent. (For example, consider a transformer with a nameplate impedance of 7 percent. The allowable variation of impedance in a paralleled unit is 7.5 percent of the nameplate

impedance or 0.525 percent. The paralleled transformer, therefore, should have an impedance between 6.475 percent and 7.525 percent.) If this limitation is not observed, the transformers will not divide the load proportionately, so that the transformer having the lower impedance (on a common base) may be seriously overloaded. The higher characteristic impedance of mobile units on a forced-cooled base also causes a greater voltage drop under load and places a heavier duty on voltage regulating equipment.

b. <u>Cooling System</u>

Mobile units customarily use a forced oil-forced air cooling system that is more complex than the self-cooled system common in permanent substations. Caution: Before this additional fan and pump load is placed on the substation station power system, its capacity should be carefully checked. There are several features that are desirable in the cooling system to reduce operating troubles and to facilitate maintenance and repair:

(1) Valves should be installed in the oil piping between the heat exchanger and the transformer tank. These allow maintenance of the forced oil cooling equipment without drawing down oil in the transformer tank.

(2) A flow type relay should be installed in the forced oil system to sound alarm or trip the breaker if oil circulation is blocked. If oil circulation or cooling is lost, a mobile unit has no load carrying capability and it can remain energized only for a few hours without load, before excessive overheating would occur.

(3) Fan and pump motors should have individual disconnecting switches to expedite fault location.

(4) The oil piping should preferably have welded joints and flange connections. Threaded connections are not recommended for mobile units because of possible loosening during transport.

c. High Voltage Connections

Connections from mobile units to permanent substations or to overhead lines should be as short as possible. Insulated cables of the shielded type may be used where connections are quite long or exposed enough so that bare conductors may be a hazard. Cables should be equipped with suitable terminations (stress cones, potheads) at each end. Because of the expense of higher voltage (69 kV and above) cable and terminations, it is especially desirable that the primary connections be short, so that bare vertical jumpers can be used safely. The ease with which connections can be made is a major factor in determining the speed with which a mobile unit may be put into service. It may be desirable to store at the substation any large pieces of equipment required to complete the installation, such as temporary wood poles, insulators, etc.

d. Alarm Connections

The mobile unit's alarm circuits should be temporarily connected to the substation alarm bus. Alarm indications should be considered for such items as hot oil temperature, low oil level, high combustible gas content, breaker lock-out, security gate open or unlocked, and any other important indications of abnormal conditions.

e. Safety

A mobile unit must always be considered as live and dangerous when in an operating position. Great care should be exercised in grounding the trailer and neutrals. Effective barriers around and under live parts should be provided wherever necessary. Interlocks should be considered to prevent energizing the unit if any required barriers are not properly in place. Additionally, a fence should be constructed around the entire mobile unit unless its operating position lies inside the substation's security fence.

f. Optimization

Because of the different application of mobile units as compared to regular substation components, it is often acceptable to consider the mobile unit as a tool that is to some extent expendable. This approach

will permit reasonable deviation from strict application of many major, basic electrical properties.

Reduced insulation levels, higher temperature ratings, higher impedance, more extreme overloading (into the loss of life range) and reduced clearances can all be considered as possible tradeoffs to obtain more transformer kVA capacity and voltage selection flexibility. Other optimal application considerations may be found through discussions with suppliers of mobile units. As mentioned earlier, minimum safety requirements must not be sacrificed to obtain other advantages.

g. Protection

In designing the protection for a mobile unit, consideration should be given to two factors that distinguish it from the normal substation situation: (1) A mobile unit is much more expensive and, (2) The temporary nature and perhaps hurried installation may increase the probability of a fault. Both factors may dictate a better than normal protection scheme.

h. Installation Requirements of Mobile Units at the Substation

Chapter IV Physical Layout discusses many of the considerations for installation of mobile units at the substation.

7. Accessories Included with the Mobile Unit

All accessories necessary for proper operation of the mobile unit should be placed at convenient locations on the trailer. Accessories that are readily available at the locations where the unit is expected to be used may be omitted. Determining which accessories to mount on board will require a careful study of all sites, as well as space availability on the trailer.

Types of accessories to be considered include power cable and connectors, grounding cables and connectors, power supply transformers, control batteries, heaters, lights, plug outlets, spare fuses, fencing and special equipment or tools for mobile unit components and trailer.

CHAPTER VI - SITE DESIGN

A. GENERAL

The objective of site work design for a substation yard is to provide an easily accessible, dry, maintenance free area for the installation and operation of electrical substation equipment and structures. Factors related to the actual location of the substation site are covered in Chapter II.

The Engineer should make a personal site inspection before the design is started. He should take advantage of the natural drainage and topographical features in the design consistent with the electrical layout since coordination of the two is essential.

B. TYPES OF GRADED YARDS

There are generally three basic profiles for substation yards -

Flat - most prevalent (Fig. VI-1)

Sloped - occasionally required (Fig. VI-2)

Stepped - seldom required (Fig. VI-3)

1. Flat Yards

The basic flat yard is more desirable for the layout and operational function of the substation. It permits uniformity in foundation elevations and structure heights. Unless property restrictions, severe topographical features, subterraneous rock or other considerations dictate otherwise, the yard should be nominally flat. (See Drainage Considerations)

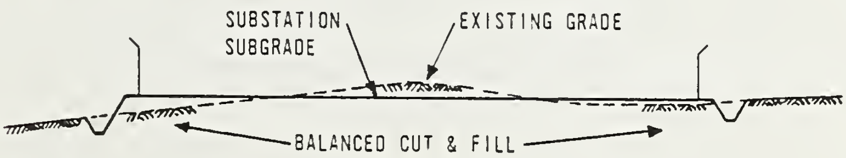


FIGURE VI-1 FLAT YARD

2. <u>Sloped Yards</u>

Occasionally, property restrictions or economic considerations will outweigh the desirability for a flat yard, and a continuously sloping yard may be advantageous.

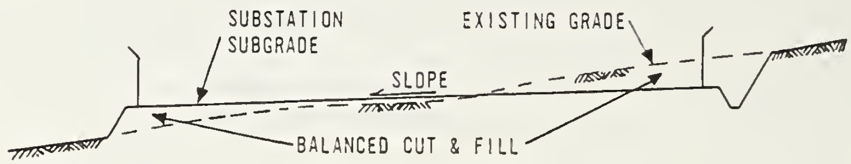


FIGURE VI-2 SLOPED YARD ON MODERATELY SLOPED SITE

3. <u>Stepped Yards</u> (two or more levels)

Stepped yards are usually created by extreme property restrictions, adverse mountainous terrain conditions or underlying rock formations making excavation uneconomical.

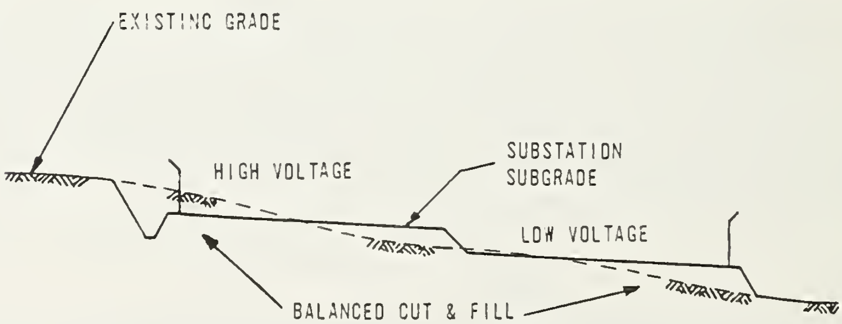


FIGURE VI-3 STEPPED YARD

Modification of any of the three types may be necessary to arrive at the optimum yard design. Sloped and stepped sites entail extra design considerations and close coordination with the electrical layout. There may be more structures required and variable foundation elevations.

C. PRELIMINARY REQUIREMENTS

The following is a short list of basic information required for the site preparation design for a substation yard:

1. Area maps (aerial photos if available).

2. Topographic drawing of immediate area showing:

   a. Ground elevations on a grid system at 15m (50 ft.) spacing.

   b. Location and elevation of existing roads, railroads, ditch inverts and culverts.

   c. Location of pertinent overhead or underground utilities, particularly the exact location and depth of any pipe lines.

   d. Property plan (legal description of property).

   e. Location of the area's drainage exits.

   f. High water elevation in area, if any.

3. Soil borings in immediate site area.

D. DRAINAGE CONSIDERATIONS

1. Surface Drainage System

Generally all three profiles lend themselves to a surface run-off system. This consists of a gently sloping (0.5% to 0.75%) ground surface so that the water drains to the edge of the yard or to shallow ditches within the yard. The ditches may discharge into culverts or shallow open channels removing the runoff from the yard.

2. Closed Drainage System

A closed drainage system is a network of catch basins and storm sewer pipe which provide a more positive means of

yard drainage. This system is quite costly. Circumstances other than economics, however, may require the use of this system. Rural type substations will rarely require a closed drainage system.

3. Planning

The yard surface drainage must be coordinated with the location of cable trenches and roads within the yard. The yard profile (flat, sloped or stepped) may present varying drainage design considerations. Careful review of the quantity, quality and particularly the location of the discharge water from the yard is emphasized. Planning the initial drainage system for a future substation addition is sometimes required. Generally a good rule to follow is: do not discharge any more water into an existing drainage area outlet than what originally occurred. Small intercepter ditches strategically located will prevent erosion of slopes or embankments.

4. Design

Whenever it is necessary to calculate the amount of rainfall run-off for the design of culverts, storm sewer pipes or ditches, a widely used and accepted method is the "Rational Method."

The Rational Method Formula is $Q = CiA$

A = drainage area in m^2 (acres)

i = average rainfall intensity m/hr (in/hr) for the period of max rainfall of a storm of a given frequency of occurrence, having a duration equal to the "time of concentration (tc)"

tc - time required for run-off from remotest part of drainage area to reach the point under design

C = run-off coefficient

Q = quantity m^3/hr (cfs) (Note: Metric units must be converted to m^3/s for Chezy-Manning Formula.)

Figures VI - 4 a, b & c provide information to assist the engineers in determining the rainfall intensity for different geographical areas, durations and recurrence intervals. Additional information concerning rainfall and frequency is available from US Weather Bureau Offices

and other technical and hydrological publications. Tables showing runoff coefficients for various types of terrain and gradient are available in texts on this subject.

DURATION IN MINUTES	FACTOR	DURATION IN MINUTES	FACTOR
5	2.22	40	0.8
10	1.71	50	0.7
15	1.44	60	0.6
20	1.25	90	0.5
30	1.00	120	0.4

RAINFALL INTENSITY CONVERSION FACTORS

RECURRENCE INTERVAL IN YEARS	FACTOR
2	1.0
5	1.3
10	1.6
25	1.9
50	2.2

RECURRENCE INTERVAL FACTORS

FIGURE VI-4a RAINFALL INTENSITY AND CONVERSION FACTORS

Frequency of storm occurrence should be two or five years and the time of concentration should be between 15 or 20 minutes for a reasonable and economical design. The design example illustrates a sample problem.

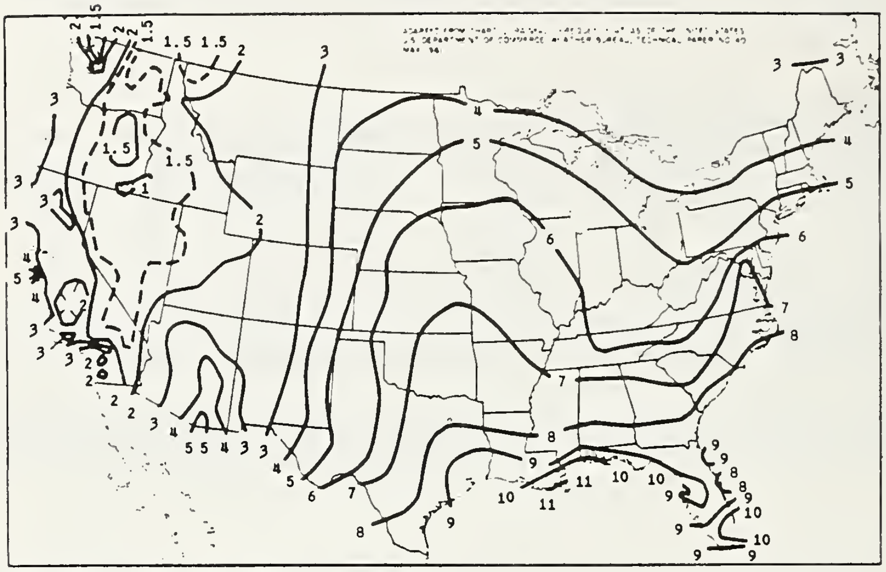


FIGURE VI-4b 2 YEAR. 30-MINUTE RAINFALL INTENSITY (CM/HR)

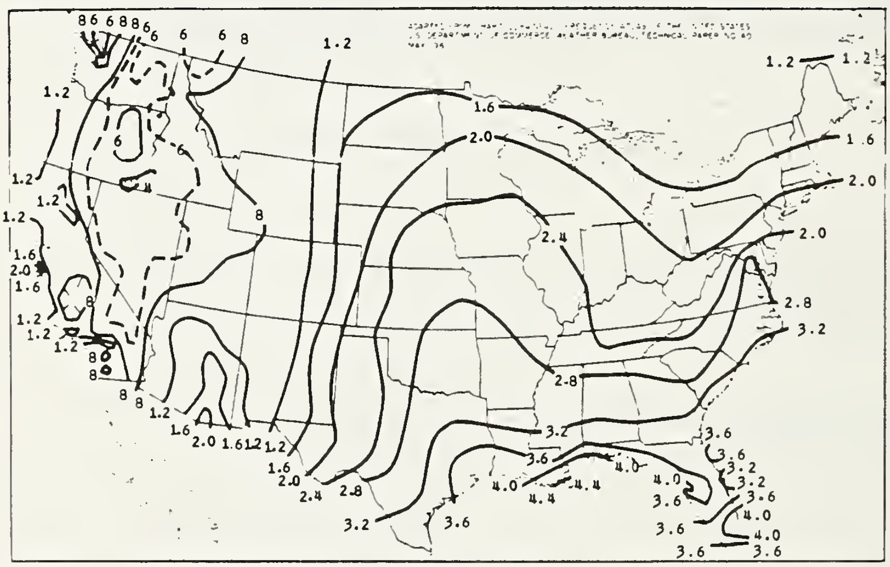


FIGURE VI-4c 2 YEAR. 30-MINUTE RAINFALL INTENSITY (INCHES/HR)

DESIGN EXAMPLE

DESIGN A CULVERT IN A SUBSTATION IN LANSING, MICHIGAN GIVEN THE FOLLOWING INFORMATION:

1. DRAINAGE AREA = $2000m^2$
2. TIME OF CONCENTRATION = 15 MINUTES
3. PERIOD OF RECURRENCE = 5 YEARS
4. COEFFICIENT OF RUNOFF = 0.50

FROM FIGURES VI-4a, b AND c DETERMINE i FOR 5 YEAR STORM OF 15 MINUTES DURATION AS FOLLOWS

	(2 YR, 30 MIN DURATION)		(15 MIN DURATION FACTOR)		(5 YR RECURRENCE FACTOR)
i =	0.05m/hr	x	1.44	x	1.3

= 0.094m/hr

THE CULVERT MUST THEN CONVEY

$Q = 0.50 \times 0.094m/hr \times 2000m^2 = 94m^3/hr$ OR

$Q = 94m^3/hr \times 1\ hr/3600\ sec = 0.026m^3/sec$

ASSUMING THAT 0.20m ϕ UNPAVED CORRUGATED METAL PIPE WILL HANDLE THE FLOW, AND USING THE CHEZY-MANNING FORMULA, DETERMINE THE SLOPE OF THE PIPE AS FOLLOWS:

$$0.026m^3/sec = 0.032m^2 \times \frac{1}{0.024} \times 0.05m^{2/3} \times s^{1/2}$$

$$s = 0.021m/m$$

$$v = \frac{0.026m^3/sec}{0.032m^2} = 0.81m/sec$$

THE VELOCITY AT THE MINIMUM SLOPE TO HANDLE THE DISCHARGE VOLUME IS NOT QUITE SELF CLEANING, BUT WOULD PROBABLY BE OKAY.

Once the quantity of water is determined by the Rational Method the actual size of storm sewer pipe, culverts or ditches may be determined by the Chezy-Manning Formula.

$$Q = AV = A \times \frac{1.0}{n} \times R^{2/3} \times S^{1/2} \text{ (metric)} \qquad \text{VI-1}$$

$$Q = AV = A \times \frac{1.486}{n} \times R^{2/3} \times S^{1/2} \text{ (English)} \qquad \text{VI-2}$$

Q = volume of pipe or ditch discharge m^3/s (cfs)

A = cross-sectional area of pipe or ditch flow m^2 (ft^2)

V = velocity = m/s (ft/s)

n = roughness coefficient for pipe or ditch

R = hydraulic radius of pipe or ditch m (ft)

$$\left(\frac{\text{Area of Section}}{\text{Wetted Perimeter}}\right) = \frac{D}{4} \text{ for pipe}$$

S = hydraulic gradient m/m (ft/ft) (slope of pipe or ditch)

After the size of pipe or ditch is determined, both minimum and maximum flow velocities should be reviewed. In order for pipes to be "self-cleaning" a minimum velocity of one m/s or three ft/s is required to prevent silting. Water in ditches, however, should be allowed to flow approximately 0.5m/s (one or two ft/s) in unprotected ditches and up to a maximum of about 1.5m/s (five ft/s) in sodded channels before erosion occurs. Special erosion protection at open discharge ends of storm sewers and both ends of culverts should be made. Flared end sections and riprap or concrete headwalls should be specified to protect these areas from scour and erosion.

E. EARTHWORK CONSIDERATIONS AND DESIGN

1. General

The computation of earthwork quantities is usually the first step toward establishing the nominal rough grade elevation of the yard.

Clearing and grubbing of the site is required and all vegetation should be removed and properly disposed of. Generally, the topsoil in the substation area is removed and stockpiled for future use during seeding.

CAUTION - When there may be a question of determining what consists of topsoil material, the Engineer should define as specifically as possible the limits of topsoil stripping.

2. Borrow

When the natural grade of the proposed site is essentially flat, it may be necessary to bring in fill material (borrow) to improve the drainage condition of the yard. However, the Engineer should avoid the use of borrow in the site design if feasible.

The borrow material should consist of a satisfactory soil free from sod, stumps, roots or other perishable or deleterious matter. It should be capable of forming a stable embankment when compacted in accordance with the requirements of this section. Acceptable soils for borrow as identified by the Unified Soil Classification System are GW, GP, GM, GC, SW, SP, SM and SC. (See Table VI-1).

The borrow pit should be located on the property if possible. If the borrow pit is located at remote distances from the site, the Engineer should reevaluate the site design to avoid hauling borrow long distances.

3. Topsoil

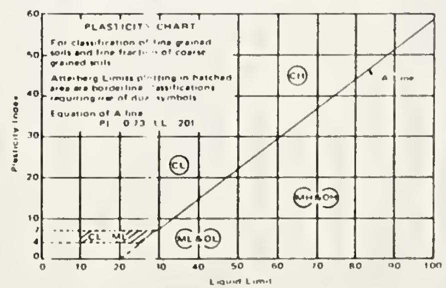
Removing topsoil on flat natural sites increases the borrow or fill requirements. Conditions when it would be excessively uneconomical to remove all of the topsoil might be:

a. Excessive depth of topsoil - 0.5m (18") and deeper.

b. When borrow material must be hauled long distances.

The Engineer should evaluate alternatives to stripping the topsoil in such circumstances.

TABLE VI-1 UNIFIED (ASTM) SOIL CLASSIFICATION SYSTEM

Major Divisions			Group Symbols	Typical Names	Classification Criteria		
Coarse-Grained Soils More than 50% retained on No. 200 sieve*	Gravels 50% or more of coarse fraction retained on No. 4 sieve	Clean Gravels	GW	Well-graded gravels and gravel-sand mixtures, little or no fines	Classification on basis of percentage of fines: Less than 5% pass No. 200 sieve GW, GP, SW, SP; More than 12% pass No. 200 sieve GM, GC, SM, SC; 5% to 12% pass No. 200 sieve Borderline classification requiring use of dual symbols	$C_u = D_{60}/D_{10}$ Greater than 4 $C_z = \frac{(D_{30})^2}{D_{10} \times D_{60}}$ Between 1 and 3	
			GP	Poorly graded gravels and gravel-sand mixtures, little or no fines		Not meeting both criteria for GW	
		Gravels with Fines	GM	Silty gravels, gravel-sand-silt mixtures		Atterberg limits plot below "A" line or plasticity index less than 4	Atterberg limits plotting in hatched area are borderline classifications requiring use of dual symbols
			GC	Clayey gravels, gravel-sand-clay mixtures		Atterberg limits plot above "A" line and plasticity index greater than 7	
	Sands More than 50% of coarse fraction passes No. 4 sieve	Clean Sands	SW	Well-graded sands and gravelly sands, little or no fines		$C_u = D_{60}/D_{10}$ Greater than 6 $C_z = \frac{(D_{30})^2}{D_{10} \times D_{60}}$ Between 1 and 3	
			SP	Poorly graded sands and gravelly sands, little or no fines		Not meeting both criteria for SW	
		Sands with Fines	SM	Silty sands, sand-silt mixtures		Atterberg limits plot below "A" line or plasticity index less than 4	Atterberg limits plotting in hatched area are borderline classifications requiring use of dual symbols
			SC	Clayey sands, sand clay mixtures		Atterberg limits plot above "A" line and plasticity index greater than 7	
Fine-Grained Soils 50% or more passes No. 200 sieve*	Silts and Clays Liquid limit 50% or less		ML	Inorganic silts, very fine sands, rock flour, silty or clayey fine sands			
			CL	Inorganic clays of low to medium plasticity, gravelly clays, sandy clays, silty clays, lean clays			
			OL	Organic silts and organic silty clays of low plasticity			
	Silts and Clays Liquid limit greater than 50%		MH	Inorganic silts, micaceous or diatomaceous fine sands or silts, elastic silts			
			CH	Inorganic clays of high plasticity, fat clays			
			OH	Organic clays of medium to high plasticity			
Highly Organic Soils			PT	Peat, muck, and other highly organic soils	Visual-Manual Identification, see ASTM Designation D 2488		

One alternative when conditions do not seem favorable for removing topsoil is to uniformly mix the topsoil with the underlying soil. The mixture is very often suitable for embankments up to three feet.

The mixture may also be compacted in-place and serve as a satisfactory bearing base upon which to build the embankment. The Engineer should assure himself that the soil to be mixed with the topsoil is predominantly granular soil. Silts or clays would not be suitable. The mixture should consist of one or more parts of good soil to one part of topsoil.

When alternatives to topsoil removal are considered, the foundation design should take into account the depth at which the soil conditions have been altered.

4. Cut and Fill

On other than flat natural grade conditions, the nominal elevation of the yard is usually determined upon a balance between the required earth "fill" for the embankment and the available earth which must be excavated or "cut" from the higher areas of the site. All cut and fill slopes should be one vertical to four horizontal if possible.

Cut and fill quantities are computed by the "average end area method" which is explained in most surveying books. Briefly, the method consists of drawing cross sections taken at every 15 m (50 ft) or 30 m (100 ft). The areas of cut and fill are determined from the computed sections with a planimeter. The sections are usually drawn with a vertical scale exaggeration of ten times the horizontal scale. The sections show both the existing profile and the proposed profile.

To compute the earthwork, the "cut" and "fill" areas of each section are totaled separately and added to the "cut" and "fill" quantities of the adjacent section.

The average of the cut summation and the average of the fill summation for each pair of adjacent sections are multiplied by the distance between sections to obtain the volumes of cut and fill. This procedure is followed at each section plotted across the substation yard.

Usually several adjustments to the proposed elevation are necessary to balance the earthwork. Only 80 to 85 percent of cut volume, as previously computed, is assumed to be available for fill. The 15 to 20 percent reduction allows for losses due to compaction, spillage and unsuitable material.

5. Compaction

Adequate compaction during placement of the fill is necessary to develop the required soil bearing capacity and lateral resistance for the foundation design. It is necessary also to prevent settlement due to consolidation of the embankment which may result in ponding, broken ducts, conduits, cable trenches, etc. All fill areas should be compacted in 200 mm± (8" ±) layers to 95 percent of the maximum density obtained by AASHTO T180. The base upon which the embankment is constructed should also be loosened and compacted.

6. Clean-Up

Upon completion of the site work all excavated earth not used in backfilling should be leveled off or shaped to present a neat appearance and not obstruct any drainage. Borrow pits should be graded to a smoothly contoured shape. It may be necessary to provide seeding mulching to such areas.

F. ROADS & OTHER ACCESS

1. General Access Roads

Access roads into substation yards must be adequate to sustain heavy equipment under all weather conditions. Long access roads require similar design considerations as most secondary county or state roads. Any culverts or sewer crossings must also be designed for anticipated heavy equipment loads.

2. Grade

The maximum grade on the access road should generally not exceed seven percent so that heavy transformers may be transported to and from the yard by normal movers without problems. Ten percent grades may be tolerated for short distances 60 -100m (200-300 ft).

3. <u>Curvature</u>

The inside radius of the access road at 90 degree intersections with major roads should not be less than 15 m (50 ft) in order to provide sufficient turning space for long vehicles. Smaller radii may be adequate for substations below 230 kV.

4. <u>Design</u>

Where space allows, access road should be about 6 m, (20 ft) wide. The road should be crowned at the center for drainage.

The subgrade for the road should be prepared and compacted to the same requirements as the embankment for the yard.

The wearing course for access roads in substations up to 69 kV may consist of a 200 mm (8 in.) deep aggregate base course. State highway department standard specifications usually contain several different types of base course material.

For larger substations, the access road may consist of a 200 mm (8 in.) aggregate base course and a 100 mm (4 in.) aggregate surface course. Highway standard specifications include several types and specify the related material and gradation requirements for the base and surface course material.

Application of the wearing courses should be made in accordance with highway standard specification.

5. <u>Railroad Spur</u>

Railroad spurs may be economically feasible at some substation locations. Coordination with the responsible railroad company will usually determine the requirements for making the turn-out. Often times the railroad company will insist on installing the track for a specified length from the main line. Normally the railroad company's standards are specified in regard to ballast, ties, rails and connections. The compaction requirements used for the yard embankment are adequate for the spur track subgrade.

6. Roadways in the Substation Yard

Many substations do not have any specific drives or roads within the fenced yard. The entire yard is considered as drivable by light traffic.

If it is desirable to have specific drives within the fenced yard for access to transformer banks or as a perimeter drive, the wearing surface can be the same as for the access road. The width may be reduced to 5 m (16 ft) or even less. Inside radii for interior drives may be 7.5 m (25 ft) or less as space allows. Culverts and cable troughs should also be designed for anticipated heavy equipment loads.

G. EROSION PROTECTION

1. General

All cut and fill slopes, ditches and all other areas outside the fenced yard in which topsoil or vegetation was removed should be protected from wind and water erosion.

In most cases topsoiling, fertilizing, mulching and seeding are sufficient and economical for erosion protection. Topsoil should be placed about 100 mm (4 in.) thick. The local agricultural extension office or the highway department should be consulted for appropriate types and application rates of fertilizer and seed.

Slopes greater than 1 vertical to 2-1/2 horizontal may require sodding. The Engineer should attempt to keep slopes at one vertical to four horizontal for erosion and maintenance purposes.

Riprap should be used at corners and intersections of ditches where erosion is likely.

2. Legal Requirements

Because of the large amount of land under construction each year, erosion and sedimentation control during construction has become a problem. Many states and localities now have laws or ordinances to control soil erosion on construction sites and the sedimentation of adjoining waterways.

The Engineer should be aware of such state laws which are usually enforced by the counties. Many counties have extensive guidelines which must be strictly adhered to. County agricultural extension offices should be consulted for these requirements.

The soil erosion and sedimentation control acts may mean considerably more engineering time to develop drawings to show compliance with the requirements of the act.

H. YARD SURFACING MATERIAL

1. General

It is desirable to have 100 to 150 mm (4-6 in.) of crushed stone or rock cover the entire substation yard and to extend 1 m (3 ft) beyond the substation fence. In some geographical locations clam and oyster shell may also be used. The yard surface material helps minimize weed growth, provides a clean, reasonably dry walking surface during wet periods, dissipates erosion effect from rain and contributes to better access drives for light vehicles.

In cases where a more substantial and unlimited drive area is desirable, a 100 mm (4 in.) layer of well graded gravel (highway aggregate base course material) is placed and rolled firm. A 75 mm (3 in.) layer of crushed stone or rock may then be placed on top. In areas where clam and oyster shell is available a very durable drive surface is easily obtained.

The size of stone for yard surfacing material should generally vary between 10 mm and 25 mm (3/8 to 1 in.). Usually the state highway department has gradations in this range.

The material selected for yard surfacing may be affected by the electrical grounding design. (See Chapter IX for details.) Because of electrical fault currents, surfacing material may need to be specified differently than would otherwise be the case. It may be desirable to have a 100 to 150 mm (4 to 6 in.) layer of crushed rock as coarse as can reasonably be walked on, with as few fines as practical or nominally available.

Before the yard surfacing material is installed, the yard surface should be brought to its proposed elevations and rolled to a reasonable firm condition. A soil sterilizer

may be applied to prevent the growth of grass and weeds at this time. The yard stone or shell should then be spread evenly as practical but need not be rolled. This work should not commence until all substation work is essentially completed.

I. SECURITY FENCE

1. General

Generally all outdoor substations are enclosed by a security fence, as discussed in Chapter II.

The fence should be installed as soon as practicable after the site work is completed. This work is usually done by a fence contractor and is not necessarily a part of the general contract.

A typical specification for material and installation of chain link style security fence is a part of this chapter. Bear in mind that numerous other rail, post and gate frame component designs will serve at least equally as well as those noted in the typical specification.

SAMPLE
SUBSTATION SECURITY FENCE SPECIFICATION

A. GENERAL

This Specification covers the requirements and general recommen dations for material and erection of security fencing for substations.

The substation fence shall consist of woven steel fabric on steel posts. It shall be a minimum of 2438 mm (8 ft) high with line posts no greater than 3048 mm (10 ft) apart. More specific requirements are further described under the Material and Erection sections of this Specification.

The primary components of the fence are:

a. Fabric
b. Line Posts
c. End & Corner Posts
d. Gate Posts
e. Top Rail
f. Barbed Wire
g. Extension Arms
h. Stretcher Bars
i. Post Braces
j. Tension Wire
k. Gate Frames
l. Hardware (Hinges, Latches, Stops, Keepers, Ties, Clips, Bands)

B. MATERIAL

1. Fabric

The fence fabric shall be a minimum of 2134 mm (7 ft) high. It shall consist of a minimum No. 9 USWG steel wire, woven into a 51 mm (2 in) square mesh. The minimum breaking strength of wire shall be 5338 N (1200 lbs). The sides of the mesh pattern shall be approximately 45° to a vertical line.

The fabric shall be galvanized in accordance with ASTM A392, Class II.

2. Line, End, Corner, Pull and Gate Posts

All posts shall be steel and conform to the sizes as listed in Table VI-2 for the specific type of application.

Tubular material should conform to ASTM A53 Grade B, for round shapes and ASTM A500 Grade B or ASTM A501 for square shapes. Roll-formed sections shall meet the yield stress requirements of ASTM A36 as a minimum.

Line Posts and Gate Posts shall be of sufficient height to; (a) accommodate a 2134 mm (7 ft) fabric; (b) accommodate extension arms, and (c) be embedded 914 mm (3 ft) into the concrete footing.

End, Corner and Pull Posts shall be of sufficient height to (a) accommodate a 2134 mm (7 ft) fabric; (b) accommodate extension arms or extend 305 mm (1 ft) extra, and (c) be embedded 914 mm (3 ft) into the concrete footing.

All tubular posts shall be galvanized in accordance with ASTM A120. Roll-formed sections shall be galvanized in accordance with ASTM A123.

3. Top Rail

Top rails shall be round steel pipe or tubing. The minimum size shall not be less than 41 mm (1-5/8 in) OD nor have a minimum wall thickness less than 4 mm (.138 in). Lengths should be a minimum of 5 m (16 ft). Provisions for adequately joining lengths together and securing to end or corner posts shall be compatible for the physical size of the top rail.

Top rails shall be galvanized in accordance with ASTM A120.

4. Barbed Wire

Barbed wire shall consist of two strands of 12-1/2 USWG steel wire with 4-point barbs at a maximum spacing of 127 mm (5 in) apart. The wire shall be galvanized after weaving in accordance with ASTM A121, Class 3.

5. Extension Arms

The extension arms shall extend upward and outward from the fence at an angle of 45 degrees. There shall be pro-

TABLE VI-2

FENCE POSTS FOR 2440 mm (8 FT) FENCE

Use	Type	Minimum Size
Line Posts	Round	Metric: 60 mm OD; t = 4 mm English: 2-3/8 in. OD; t = .154 in.
	Square	Metric: 50 mm sq; t = 4.25 mm English: 2 in. sq; t = .1875 in.
	Rolled or Formed Section	Size so that bending strength about strong axis is not less than that of the round post.
End, Corner, Pull Posts	Round	Metric: 73 mm OD; t = 5 mm English: 2-7/8 in. OD; t = .203 in.
	Square	Metric: 63 mm sq; t = 4.75 mm English: 2-1/2 in. sq; t = .1875 in.
	Rolled or Formed Section	Size so that bending strength about weak axis is not less than that of the round post.
Gate Posts	Round	Metric: 100 mm OD; t = 5.75 mm English: 4 in. OD; t = .226 in.
	Square	Metric: 76 mm sq; t = 6 mm English: 3 in. sq; t = .25 in.
	Rolled or Formed Section	Size so that bending strength about weak axis is not less than that of the round post.

visions for three equally spaced lines of barbed wire on the extended arms. The uppermost wire shall be approximately 305 mm (1 ft) vertically above the fabric.

The extension arm shall be made of pressed steel or malleable iron and should be capable of supporting a downward force of 1334 N (300 lbs).

The extension arm shall be galvanized in accordance with ASTM A153, Class B1.

6. Stretcher Bar

Stretcher bars shall be galvanized steel bars not less than 6 x 19 mm (1/4 in x 3/4 in). They shall be approximately 25 mm (1 in) less than the fabric height.

The stretcher bar shall be used for securing the fabric to all terminal posts. One bar is required for each gate and end posts and two required for each corner and pull post.

7. Post Braces

Post braces are required at each gate, corner, pull and end post. It shall consist of a strut, which shall not be less in size than the top rail, and a tension rod with turnbuckle. The rod shall be steel and have a minimum diameter of 10 mm (3/8 in).

The strut shall be secured to the adjacent line post at approximately mid-height of the fabric. The tension rod is also secured near this area on the line pole and is anchored near the base of the corner post (or gate, pull or end post).

Bracing members shall all be hot-dip galvanized per ASTM 153.

8. Tension Wire

Tension wire shall not be less than No. 7 USWG galvanized steel wire.

9. Gate Frames

Gate frames shall be constructed of tubular steel members which shall be welded at the joints. Additional horizontal and vertical struts may be required to provide for a

rigid gate panel allowing for no visible sag or twist. Gate frames shall be made to have approximately 76 mm (3 in) clearance above the road.

Fabric for the gate panels shall be the same as the fence.

Gate frame and bracing members shall not be less than the structural equivalent of 48 mm (1.9 in) OD standard pipe. Steel tension rods and turnbuckles may also be utilized. Gate frame shall have provisions for three lines of barbed wire above fabric. All gate frame material shall be hot-dip galvanized.

10. Hardware

Hinges shall be heavy duty and allow 180 degree swing of all gate leaves. The hinges shall not twist or turn under the action of the gate and shall provide ease of operation.

Latches, Stops and Keepers shall all be heavy duty construction of galvanized steel or malleable iron. Latches shall have a heavy duty drop bar. The center stop shall be made to be cast in concrete and engage the drop bar. A keeper shall be provided which will secure the free end of the gate in the open position.

Hardware shall allow for gate operation from either side with provisions for securing with padlock.

Bands, Wire Ties and Clips for securing fabric to top rails, line posts, terminal posts and tension wires shall be galvanized steel and of adequate strength for the purpose intended. Aluminum wire ties of adequate strength are acceptable for this work also.

C. ERECTION

The fabric shall be placed on the outside of the posts, stretched taut and secured to the posts, top rail and tension wire. The fabric shall be secured to the line posts with wire ties or metal bands at maximum intervals of 356 mm (14 in). The top and bottom edges shall be secured, respectively, to the top rail and tension wire with tie wires not exceeding intervals of 610 mm (24 in). The fabric shall be secured to terminal posts by means of the stretcher bar which is passed through the end loops of the fabric and is secured to the terminal posts by metal bands spaced at a maximum interval of 356 mm (14 in).

Fabric for fencing shall all be either a left-hand or right-hand weave. Rolls of fabric shall be joined together by weaving a single strand into the end of the roll to form a continuous piece.

The spacing of line posts (3 m or 10 ft max) shall in general be measured parallel to the ground. All posts shall be placed in a vertical position except as may be specifically designated otherwise, with the strong axis parallel to the fabric.

All posts shall be set in holes and backfilled with concrete. Concrete shall have a maximum compressive strength of 1720 N/cm^2 (2500 psi) at 28 days with a maximum size of aggregate of 25 mm (1 in). The concrete shall be well worked (rodded) in the hole. The top of the footing shall be crowned to shed water.

The minimum diameter of holes for line posts shall be 229 mm (9 in) and for terminal posts 305 mm (12 in). See Figure VI-5 for erection details.

The minimum depth of the footing holes shall be 965 mm (38 in). CAUTION: The Engineer should review footing depth in areas subject to extreme frost penetrations and in areas of solid rock with very little or varying amounts of soft overburden.

D. <u>GROUNDING</u>

Fencing grounding shall be in accordance with Chapter IX.

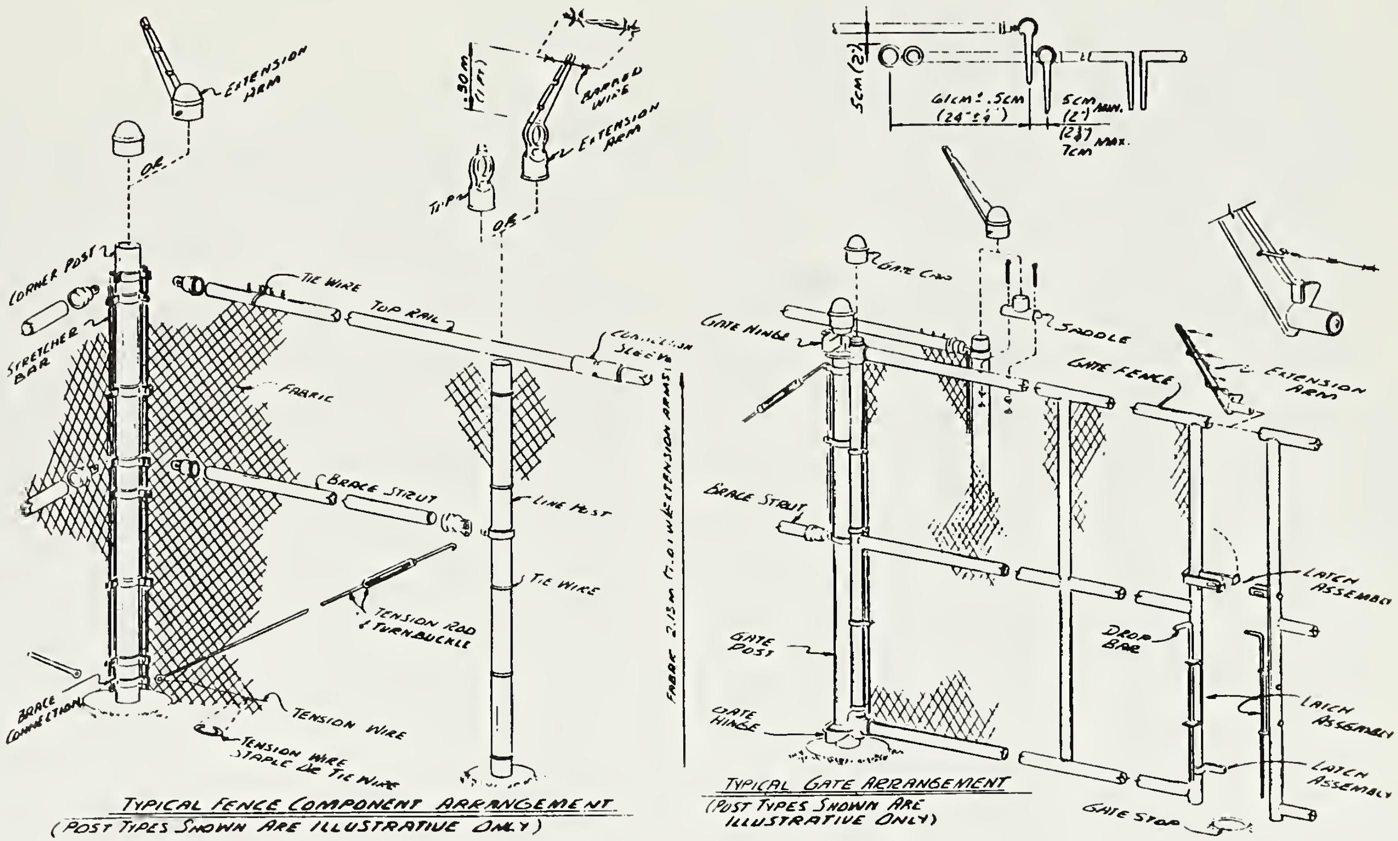


FIGURE VI-5 FENCE ERECTION DETAILS

REFERENCES

Handbook of Steel Drainage & Highway Construction Products, Second Edition, 1971, American Iron and Steel Institute

The American Association of State Highway and Transportation Officials

T180 Standard Method of Test for Moisture-Density Relations of Soils Using a 10-lb Rammer and an 18-in Drop

U.S. Department of Agriculture, Soil Conservation Service

Agriculture Bulletin 347, Controlling Erosion on Construction Sites

Portland Cement Association

PCA Soil Primer

CHAPTER VII - STRUCTURES

A. GENERAL CONSIDERATION

Prior to the start of structure design, several factors should be evaluated that may have an affect on the proper choice of material and member type selected for the structure.

Factors influencing selection of material and member type include: First cost, cost of erection, deflection characteristics, cost of maintenance, availability, resistance to corrosion and other deterioration, freedom from fire hazard, appearance, size of revenue-producing load served and temporary or permanent nature of structure.

B. MATERIALS

There are four basic types of material used for substation structures - steel, aluminum, concrete and wood.

1. Steel

Steel is used for most substation structures. Its availability and good structural characteristics generally make it economically attractive. Steel, however, must have adequate protection from the elements to prevent corrosion. Galvanizing and painting are two widely used finishes for steel substation structures. Because of the protective finish, steel substation structures should not be designed for field welding or field drilling for connections. Field welding is generally uneconomical and usually requires close control over the welding conditions.

ASTM A36 steel is the standard grade steel used for most rolled shape members in structure design. Member stresses are usually low and weight saving is of little advantage. However, should large loads be encountered coupled with the need for weight reduction, a high strength steel should be considered. Structures requiring such consideration are the line support structures. Structural steel pipe and square tube sections are normally constructed of ASTM A53 Grade B and ASTM A501 steel, respectively.

2. Aluminum

Aluminum is sometimes used for substation structures where good corrosion resistant properties are desired. It is about one-third the weight of steel.

If aluminum is used, member types should be selected taking advantage of the optimum structural qualities of aluminum and avoiding the shapes in which aluminum members may be a problem. Deflection and torsion must be carefully reviewed when selecting member types in aluminum.

Aluminum has a lower modulus of elasticity, $E = 6.9 \times 10^6$ N/cm^2 (10×10^6 psi), and modulus of elasticity in shear, $E_s = 2.6 \times 10^6$ N/cm^2 (3.8×10^6 psi) than steel, $E = 20 \times 10^6$ N/cm^2 and $E_s = 8.3 \times 10^6$ N/cm^2 (29×10^6 psi & 12×10^6 psi). These properties are directly related to deflection and torsional rotation.

Structures designed for aluminum are constructed of Alloy 6061-T6 and should be designed, fabricated and erected in accordance with the Aluminum Association's Specifications for Aluminum Structures.

3. Concrete

Precast, prestressed concrete substation structures may be economical when substations are located near the fabricator's plant. Special considerations are required for the foundation, erection, handling and the equipment mounting characteristics of the structure.

4. Wood

Wood may be used for substation structures. Members must be treated with an appropriate preservative. Wood poles and members are usually readily available. Structural properties and size tolerances of wood are somewhat variable and design considerations should take this into account. The life of a wood structure is shorter than for steel, aluminum or concrete, and maintenance costs may be higher.

Economics is an important consideration when making a material and member type selection. The total cost over the life of the structure should be considered. This also includes the cost of fabrication and shipping, ease of erection and cost of maintenance.

C. FUNCTIONAL STRUCTURE TYPES

There are essentially three types of substation structures which may be categorized from a structural design approach related to the function served in the substation.

1. Line Support Structures

These structures are used as line exit structures, internal strain bus structures and line terminating structures. They consist basically of two high towers and a crossarm on which the line conductors are attached. They may be used as single bay or multibay structures.

The major forces acting on these structures are the shield wire and conductor tensions and wind forces. Due to the large size of the structures and magnitude of forces acting upon them, these structures are usually highly stressed and require the most design effort.

2. Equipment Support Structures

These structures are commonly referred to as bus support structures, switch stands, lightning arrester stands, line trap supports, etc.

In low profile substation design, these structures are designed primarily as vertical cantilever beams with wind and short circuit forces being the primary design forces. Deflection may control the design size of some structures and should be reviewed in all structures.

Switch stands should be designed more rigid than bus supports or other structures due to the dynamic loading effect of the switch blade operation and the requirement that the switch blade must always return (close) to the relatively small space of the saddle. Any appreciable twisting or deflection of the switch stand may prohibit this function.

3. Distribution Substation Structure

This structure is the column and beam structure, similar to a building frame. It may consist of one or several bays in length and usually is one bay wide. It may vary in height from 6 to 12 m (20 to 40 ft) or more.

The structure supports switches and other equipment. It usually will have line conductors attached to one or more sides. This structure should be designed for rigidity

and flexibility in equipment location. Generally these structures are comprised of box truss members.

D. STRUCTURE MEMBER TYPES

Three types of structure profile configurations are common in substations today. They are classified from their general physical appearance and structural member components. The types are lattice, solid profile and semi-solid profile.

1. Lattice

The lattice structure consists primarily of angle members forming the chords and lacing of a box truss acting as a beam or column.

Depending upon the function of the structure (i.e., bus support stand vs. line support structure) the design of the members may or may not be time consuming and complex.

The lattice structure has been widely used for substation structures for many years. Its box truss beams and columns allow for an efficient use of material. Usually the lattice structure results in the least structure weight compared to other line support structures. It is also very stable and rigid. It is very easy to fabricate, galvanize and ship. It requires a large amount of bolting and erection time in the field, unless the members are shipped preassembled, and maintenance painting, if required, is costly.

2. Solid Profile

The solid profile structure is made from wide flange shapes, pipes, tapered round or polygonal shapes and rectangular tube shapes. The aesthetic appearance, relatively short erection time and ease of maintenance make the solid profile structure a popular choice for equipment support structures. The weight penalty on solid profile equipment support structures is smaller than on line support structures.

The square tube has good torsional resistant properties and is equal structurally about either major axis. The wide flange shape has a minor axis which may control the design. It has an open cross section and minimal resistance to torsional loads.

Wide flange shapes are more suitable for bolted structural connections and may require less welding during fabrication.

Line support structures may be made of straight or tapered tubular round or polygonal poles. The tower may be either an A-frame configuration or a single pole. Wide flange shapes may be used in the A-frame tower. Crossarms are made of straight or tapered round or polygonal members. A combined section from wide flange shapes is used for crossarms also.

Tapered poles may have telescoping or flanged splice connections when the pole is galvanized. Painted poles may have welded splice joints and are hermetically sealed to prevent oxidation inside the pole.

Tapered poles are almost always designed by the pole fabricator to the loading requirements specified by the Engineer.

3. <u>Semi-Solid Profile</u>

The third structure type is semi-solid profile. This type of structure is made from wide flanges, pipes or tubes which form the major members and is braced between these major members with angle bracing.

The design of this structure type is similar to the lattice structure and is very stable and rigid because of the bracing.

4. <u>Summary</u>

Each of the structure member types has its advantages and disadvantages, both from an economical and design viewpoint.

Lattice structures are usually economically comparable in aluminum and steel. The basic design approach is also the same. Solid profile structures used for equipment support structures in aluminum may be as economical as steel in favorable geographical locations. Design effort for aluminum members used in equipment support structures requires more time because of buckling characteristics and weld effect on allowable stresses. However, the desirability of aluminum's good weathering characteristics and light weight are positive factors which must also be evaluated.

E. DESIGN

1. Design Loads

Design loads for substation structures should be categorized into those for: 1) line support structures; and 2) equipment support structures.

2. Line Support Structures

The design loading criteria for these structures should be very similar to the criteria for a transmission line tower. The maximum loading condition and line tension are usually furnished by the transmission engineer. For strain bus structures the substation engineer should base the design upon those design loads which will be a maximum for the various components of the structure.

A more positive determination of the structure capacity can be made if an overload is applied to the forces and the structure members are designed utilizing yield stresses. The information is also beneficial for future line changes for substation upgrading or other electrical load modifications.

The components of this structure should be able to withstand the stresses induced by the most critical loading (multiplied by an appropriate overload factor) affecting the component member.

These loadings are described in Chapter II and are listed here for overload factor correlation.

Overload factors for metal and prestressed concrete structures:

a. NESC (Heavy, Medium, Light)

(1)	Wire Pull	1.65
(2)	Wind	2.50
(3)	Vertical	1.50

b. High Winds @ 15° C (60°F)

(1)	Wire Pull	1.3
(2)	Wind	1.3
(3)	Vertical	1.3

c. Heavy Ice @-1° C (30°F)

(1)	Wire Pull	1.3
(2)	Vertical	1.3

d. Other Wind & Ice Combination

(1)	Wire Pull	1.3
(2)	Wind	1.3
(3)	Vertical	1.3

e. Seismic Loading

(1)	All Masses	1.3

The line support structure is designed for two line angle conditions: 1) all wires perpendicular to the crossarm; and 2) the angle of all wires deviating from perpendicular to the crossarm at 15 degrees. Local conditions may require a larger angular deviation.

3. <u>Deflection Consideration</u>

In addition to the stresses, the Engineer should also consider deflection limitations for line support structures. Unless particular circumstances dictate otherwise the limitations listed may be used as guidelines.

Crossarms - $\Delta h \leq 1$ to 1-1/2% of span for max tension w/OLF
Poles - (at top) $\Delta h \leq 4$ to 5% of height for max tension w/OLF

Lattice towers and solid profile A-frame towers present no problems with deflection. The single pole type line support structure must be carefully reviewed for deflection limitations, particularly if it is acting as a line dead-end structure and also is supporting backspan conductors.

4. <u>Lightning Masts</u>

Single tubular poles often are used for tall lightning masts. Consideration should be given to those poles where no shield wires are attached.

Damping devices should be included to reduce or negate vibrational type forces created by the wind blowing at or near the natural frequency of the pole.

One such device may be fairly heavy steel chain, encased in a fire hose (to protect the pole finish) and suspended from the top of the pole (inside).

5. Equipment Support Structures

These structures should be designed for all applicable wind, ice, short circuit, dead and dynamic operating loads of equipment. Steel substation structures generally should conform to the requirements of Part 36 of NEMA Publication SG 6.

Ice loading is usually not the controlling design load for equipment support structures, but should be reviewed.

Wind loads plus short circuit forces usually produce the maximum stresses in the structures.

Although not normally a critical factor on bus supports and other stationary type equipment stands, deflection limitations are important for switch stands. Deflection limitations as specified in Section SG6-36.03 of NEMA Publication SG 6 should be followed unless special conditions dictate otherwise.

Bus support structures and other stationary equipment stands should be designed for a reasonable amount of rigidity. Members stressed to near their allowable stresses may result in structures that perform unsatisfactorily.

Basically, the wind load is assumed for design purposes as a statically applied load. In reality, it fluctuates in magnitude and oscillating motion may be induced in the structures. This motion is most unpredictable but can be somewhat alleviated by selecting members that may be larger than required by the calculations and will provide reasonable rigidity for unknown effects. Allowable working stress design values should be used for equipment support structures.

6. Base Condition

Equipment support structures consisting of solid profile members may be designed either with the base plate in full contact with the foundation or resting on leveling nuts slightly above the foundation.

The design with the leveling nuts has several advantages:

a. Eliminates need for close tolerance work on foundation elevation and trueness of surface.

b. Allows for some flexibility for structure alignment due to fabrication tolerances and buswork fit up.

c. Base plate is not resting in any standing water on the foundation.

Anchor bolt sizes may be required to be slightly larger due to additional bending stress induced. Space between bottom of leveling nut and nominal top of foundation is usually 1.3 cm (1/2 inch).

7. Seismic Loads

Designing structures for seismic loading can be a very involved, time consuming procedure involving dynamic analysis and response spectra. In certain areas of high seismic risk or when sensitive equipment is to be installed, such analysis may be necessary; however, it should be performed by trained, competent people. For most design purposes, more simplified methods can be used, such as the Uniform Building Code procedure or the procedure described in the Bureau of Reclamation Design Standard No. 10 Transmission Structures, U.S. Department of the Interior.

Because of its simplicity, it is recommended that the Bureau of Reclamation procedure be used for design except where local requirements dictate or where a more exact analysis is desired. The formula used is of the form

$F = 9.8\ CW$ - Metric VII-1

$F = CW$ - English VII-2

F: horizontal force, N (lbs) in any direction applied at the center of gravity of each major component.

W: dead load of structure or electrical equipment, kg (lbs)

C: a numerical constant equal to

0.0 in Zone 0 of seismic probability
0.05 in Zone 1 of seismic probability
0.10 in Zone 2 of seismic probability
0.20 in Zone 3 of seismic probability

The zones of seismic probability are shown on various maps, which differ only slightly from one another. Figure II-2 in Chapter II is a Seismic Probability Map of the United States.

Generally, seismic loads on substation structures in Zones 1 and 2 are exceeded by wind loads; however, each situation is different and should be checked. Vertical forces are usually taken to be 2/3 of the horizontal force.

Seismic loads are usually applied alone as individual loads.

8. Wind Loads

Several methods of determining wind loads are used. The most widely used method is the ASCE Report, "Guide for Design of Steel Transmission Towers."

Wind pressures on flat surfaces are obtained from

$$P_w = .0776V^2 \qquad \text{(Metric)} \qquad \text{VII-3}$$

$$P_w = .0042V^2 \qquad \text{(English)} \qquad \text{VII-4}$$

and wind pressure on cylindrical surfaces from

$$P_w = .0481V^2 \qquad \text{(Metric)} \qquad \text{VII-5}$$

$$P_w = .0026V^2 \qquad \text{(English)} \qquad \text{VII-6}$$

P_w: pressure on the projected area, N/m^2 (psf)

V : design wind velocity, km/hr (mph)

The design wind velocity for a given area is determined from the probable wind velocity over the design life of the structure, say a 50 year period of recurrence. This information can be obtained from Figure II-1 in Chapter II or may be derived from local climatological data.

For wind loading on lattice structures, the pressure on the projected area is applied to one and one-half faces.

9. Construction Loading

Consideration should also be given to construction loads that can be periodically imposed on structures such as pulling and hoisting equipment into place. While such conditions do not usually govern design, they should be evaluated.

10. Loading Combination For Design

In addition to designing equipment stands for the extreme loads, bus supports are also designed for a combination load of extreme wind and short circuit loads. The load combination design should be limited to calculations of stress and should not consider deflection of the structure.

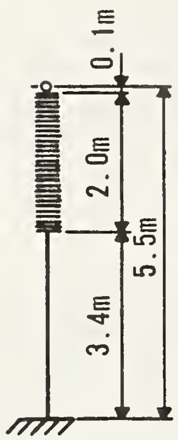
11. Typical Design Approach

Several examples are illustrated depicting the design of the main member for a single phase bus support. These examples show a typical approach for the design of most equipment support structures. The examples include a square tube, a wide flange and a lattice column, all comprised of steel.

Lighter weight members may still meet the loading and deflection criteria. However, smaller size members may present fabrication problems in the lattice structure.

In general, for voltages up to 230 kV, structures using tubular members are as economical as lattice or wide flange structures when weight, ease of fabrication and ease of erection are considered.

Design a single phase bus support for a substation in Lansing, Michigan giving the following information:



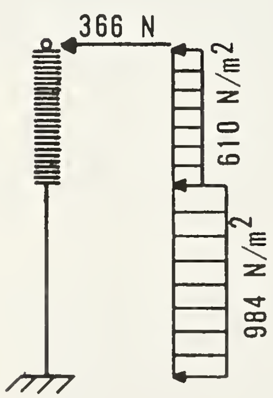
Height of bus ₵ above foundation 5.5m
Sch 40 alum bus 100mm (mass=5.J1 kg/m)
Max short circuit force 550 N/m
Short circuit reduction factor .66
Bus support spacing 6.0m
Insulator 2.0m high, .28m diam and 140 kg

a. Design a tubular structure, A500 or A501 steel

Short Circuit Loading

F_{sc}= 6.0 m x .66 x 550 N/m=2178 N

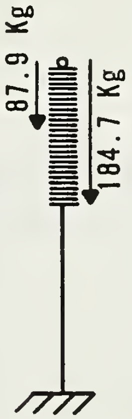
Mom @ base=5.5m x 2178N=11,980 N-m



Wind Loading

Extreme 50 year wind 112.6 km/hr
for flat surfaces
P_w= .0776 $(112.6)^2$ = 984 N/m^2
for cylindrical surfaces
P_w= .0481 $(112.6)^2$ = 610 N/m^2

Description	Force	Moment Arm	Moment @ Base
Wind on Bus	6m x 610 N/m^2 x .1 m^2/m = 366N	5.5m	2013 Nm
Wind on Insulator	2m x 610 N/m^2 x .28 m^2/m = 342N	4.4m	1505 Nm
Wind on Struct. (assume 20cm-sq)	3.4m x 984 N/m^2 x .20m^2/m =669N	1.7m	1137 Nm
TOTALS	1377N		4655 Nm



Heavy Ice Loading (25.4 mm)

Ice _____ 913.0 kg/m^3 (57 pcf)

Description		Load
Ice on Bus	$[(.151m)^2-(.100m)^2]\ \frac{\pi}{4}$ x 913 kg/m^3 =	9.14 kg/m
Ice & Bus	9.14 kg/m + 5.51 kg/m =	14.65 kg/m
Ice on Insulator	$[(.331m)^2-(.28m)^2]\ \frac{\pi}{4}$ x 913 kg/m^3 =	22.34 kg/m
Ice & Insulator	22.34 kg/m x 2m + 140 kg =	184.7 kg

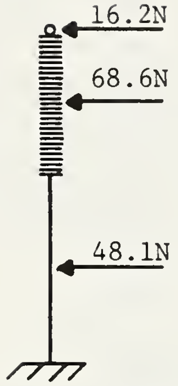
$$f_a = \frac{(14.65\ kg/m \times 6.0m + 184.7\ kg + 3.4m \times 28.89\ kg/m)\ 9.80}{14.5cm^2}\ N/kg$$

$$= 250.6\ \frac{N}{cm^2}$$

$$\frac{kl}{r} = 2\ \frac{(340\ cm)}{8.05\ cm} = 84$$

$$F_a = 10335\ \frac{N}{cm^2} > 250.6\ \frac{N}{cm^2}\ \text{okay}$$

Seismic Loading



Lansing, Michigan is Zone 1
C=0.05

Description	Force	Moment Arm	Moment @ Base
Seismic on Bus	6m(5.51 kg/m)9.8(.05) = 16.2N	5.5m	89.1Nm
Seismic on Ins.	140 kg(9.8).05 = 68.6N	4.4m	301.8Nm
Seismic on Struct.	3.4m(28.89 kg/m)9.8(.05)= 48.1N	1.7m	81.8Nm
TOTALS	132.9N		472.7Nm

Since the combined loading of wind and short circuit forces produce the greatest forces and moment at the base design for this condition. Heavy ice and seismic forces are not critical for this structure.

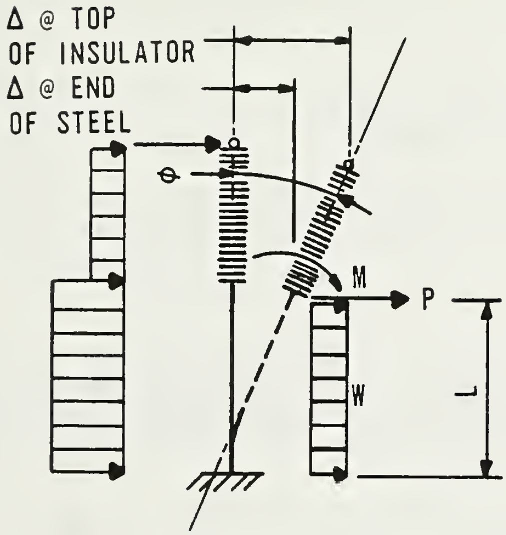
For the cantilever structure, bending and deflection are the principal concerns

Try a 20.3 cm x 20.3 cm x 0.48 cm steel tube

$$f_b = \frac{M}{S} = \frac{16{,}635\text{Nm}(100\text{cm/m})}{234.3\text{cm}^3} = 7100\ \frac{\text{N}}{\text{cm}^2}$$

$$F_b = .60\ F_y = 15160\ \frac{\text{N}}{\text{cm}^2} > 7100\ \frac{\text{N}}{\text{cm}^2}\quad \text{okay}$$

Check Deflection
(for wind only)



Deflection Equivalent Loadings

Δ @ end of steel = $\Delta_1 + \Delta_2 + \Delta_3$

Where: $\Delta_1 = \frac{Pl^3}{3EI}$, Wind on insulator & bus

$\Delta_2 = \frac{Wl^4}{8EI}$, Uniform wind on structure

$\Delta_3 = \frac{Ml^2}{2EI}$, Moment at insulator base

Δ = 0.19 cm + 0.07 cm + 0.13 cm = 0.39 cm

Θ (slope) @ end of steel = $\Theta_1 + \Theta_2 + \Theta_3$

Where: $\Theta_1 = \frac{Pl^2}{2EI}$, Wind on insulator & bus

$\Theta_2 = \frac{Wl^3}{6EI}$, Uniform wind on structure

$\Theta_3 = \frac{Ml}{EI}$, Moment at insulator base

Θ = 0.00086 rad + 0.00027 rad + 0.00079 rad = 0.00192 rad

Δ @ top of insulator = 0.39cm + 200cm sin Θ = 0.77cm

$$\frac{.77cm}{550cm} = \frac{1}{714} < \frac{1}{200} \quad \text{okay}$$

Acceptable criteria for bus support structure deflections may be taken a 1/200 of the bus height.

The analysis shows that for the given conditions a structural tube 20.3cm x 20.3cm x 0.48cm will be suitable.

b. Design a wide flange structure, A36 steel

The maximum combined loads on this structure are the same as in the first example. Again, by inspection, heavy ice loading is not critical. Therefore, consider only bending and deflection.

assume W 20.3cm x 35.7 kg/m

$$f_{bxx} = \frac{M}{S_{xx}} = \frac{16,635\ Nm\ (100m/m)}{341cm^3} = 4878\ \frac{N}{cm^2}$$

$$f_{byy} = \frac{M}{S_{yy}} = \frac{2642\ Nm\ (100cm/m)}{92cm^3} = 2872\ \frac{N}{cm^2} \text{(wind only)}$$

F_b is reduced when the unbraced compression flange is considered

F_{bxx} = 14,200N/cm^2 > 4878 N/cm^2 okay

F_{byy} = 15,170N/cm^2 > 2872 N/cm^2 okay

Check Deflection
(for wind only)

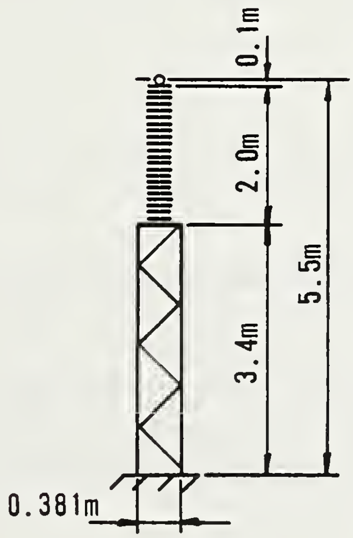
Δ_{xx} @ end of steel = 0.13cm + 0.05cm + 0.09cm = 0.27cm

Θ = .00060 rad + .00019 rad + .00055 rad = 0.00134 rad

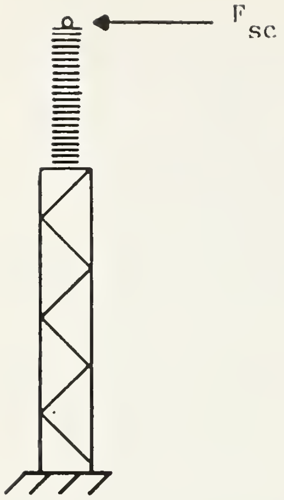
Δ_{xx} @ insulator = 0.27cm + 200cm sin Θ = 0.54cm

$$\frac{.54\text{cm}}{550\text{cm}} = \frac{1}{926} < \frac{1}{200} \qquad \text{okay}$$

c. Design a lattice structure, A36 steel
(Assume box truss 38.1cm square)



Short Circuit Loading

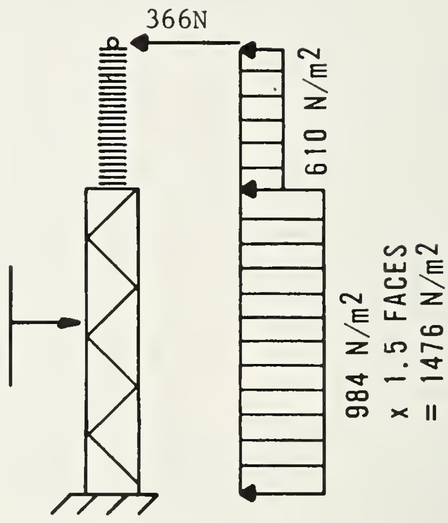


F_{sc} = 6.0m x .66 x 550N/m = 2178N

Mom @ base = 5.5m x 2178N = 11,980Nm

Wind Loading

Assume chord angles 6.35cm
Assume lacing angle 4.45cm



Description	Force	Moment Arm	Moment @ Base
Wind on Bus	6m x 610 N/m^2 x .1 m^2/m = 366N	5.5m	2013Nm
Wind on Ins.	2m x 610 N/m^2 x .28m^2/m = 342N	4.4m	1505Nm
Wind on Struct.	3.4m x 1476N/m^2 x .19m^2/m=953N	1.7m	1620Nm
TOTALS	1661N		5138Nm

By inspection heavy ice and seismic loading will not result in the maximum design loads.

Moment at the base causes tension and compression in the chord angles.

C = Tensile or compressive force

$$C = \frac{17{,}118\ \text{Nm}}{2[.381\text{m} - 2(.014\text{m})]} = \qquad 24{,}250\text{N per leg}$$

P = Applied load

$$P + C = \frac{1373\ \text{N} + 6\text{m}(54\text{N/m})}{4} + 24{,}250\text{N} = 24{,}670\ \frac{\text{N}}{\text{leg}}$$

$$\frac{kl}{r_z} = \frac{1.0(38.1)}{1.26} = 30 \quad \frac{kl}{r_y} = \frac{1.0(57)}{1.98} = 30 \quad F_a = 13{,}780\ \frac{\text{N}}{\text{cm}^2}$$

$$f_a = \frac{24{,}670\ \text{N}}{5.94\ \text{cm}^2} = 4153\ \frac{\text{N}}{\text{cm}^2} < 13{,}780\ \frac{\text{N}}{\text{cm}^2} \qquad \text{okay}$$

Δ @ top of steel = 0.07cm + 0.03cm + 0.05cm = 0.15cm
Θ = .00030 rad + .00010 rad + .00028 rad = .00068 rad

Δ @ top of insulator = 0.15cm + 200cm sin Θ = 0.29cm

$$\frac{0.29\ \text{cm}}{550\text{cm}} = \frac{1}{1897} < \frac{1}{200} \qquad \text{okay}$$

A summary of mass and deflection for the example structure designs is shown in the following table.

Description	Mass of Structure	Deflection at Insulator	Comments
20.3cm x 20.3cm x .48cm	122kg	0.77cm	Largest deflection
W20.3 x 35.7 kg/m	154kg	0.54cm	Heaviest structure
Box Truss, Chord Angles 6.35cm x 6.35cm x .48cm Lacing Angles 4.45cm x 4.45cm x .48cm	118kg	0.29cm	Smallest deflection

F. FASTENERS

Three types of structural bolts are typically used in substation structure design. These bolts are designated by ASTM Standard Specifications A394, A307 and A325. For all but the most severely loaded structures, the A394 and A307 bolts will usually be adequate.

If possible, one type of structure bolt and one diameter should be used in any one structure and throughout all the substation structures.

1. ASTM A394

ASTM Standard Specification A394 covers galvanized hex head bolts including hex nuts with sizes from 12.7 to 25.4 mm (1/2 to 1 inch) in diameter.

2. ASTM A307

Non-galvanized regular square or hex head bolt and nuts in diameters ranging from 6.35 to 101.6 mm (1/4 to 4 inch) in diameter are covered by ASTM Standard Specification A307. This Specification is also used for anchor bolts conforming to the requirements of ASTM A36 structural steel. For substation usage, Grade A bolts are used. Hot-dip galvanizing in accordance with ASTM A153 is required for substation applications.

3. ASTM A325

When high strength bolts are required, ASTM Standard Specification A325 High Strength Bolts may be used. High strength bolts are available in sizes from 12.7 to 38.1 mm (1/2 to 1-1/2 in) in diameter. Bolts, nuts and washers should be galvanized in accordance with ASTM A153, Class C. Nuts should conform to ASTM A563 Grade DH.

Some tabulated bolt values for single shear are given in Table VII-1. These values may be used for substation structure design when "working stresses" or "yield stresses" are used.

Because of the repeated loads, those structures using A307 or A394 bolts should also incorporate either lockwashers or locknuts to prevent loosening of the connections. Standard washers are not normally used with these bolts.

TABLE VII-1

Suggested Allowable Bolt Shear

SINGLE SHEAR ON BOLTS, KIPS (English Units) WORKING STRESS DESIGN						
ASTM Designation	Allowable Shear Stress Fv (ksi)	Nominal Diameter (inches)				
		1/2	5/8	3/4	7/8	1
A307 & A394	15.0	2.95	4.60	6.63	9.02	11.78
A325	24.0	4.71	7.36	10.60	14.43	18.85

SINGLE SHEAR ON BOLTS, KIPS (English Units) YIELD STRESS DESIGN						
ASTM Designation	Allowable Shear Stress Fv (ksi)	Nominal Diameter (inches)				
		1/2	5/8	3/4	7/8	1
A307 & A394	30.0	5.89	9.20	13.25	18.04	23.56
A325	40.0	7.85	12.27	17.67	24.05	31.42

SINGLE SHEAR ON BOLTS, KN (Metric Units) WORKING STRESS DESIGN						
ASTM Designation	Allowable Shear Stress Fv (kN/cm^2)	Nominal Diameter (mm)				
		12.70	15.88	19.05	22.23	25.40
A307 & A394	10.34	2.03	3.17	4.57	6.22	8.12
A325	16.55	3.25	5.07	7.31	9.95	13.00

SINGLE SHEAR ON BOLTS, KN (Metric Units) YIELD STRESS DESIGN						
ASTM Designation	Allowable Shear Stress Fv (kN/cm^2)	Nominal Diameter (mm)				
		12.70	15.88	19.05	22.23	25.40
A307 & A394	20.68	4.06	6.34	9.14	12.44	16.24
A325	27.58	5.41	8.46	12.18	16.58	21.66

G. <u>WELDING</u>

All welding of structural steel should be in accordance with the latest edition of the "Structural Welding Code," D1.1 of the American Welding Society.

Structures that are to be galvanized should have, in addition to the required design welds, all joints sealed with a small continuous seal weld. This is to help prevent corrosion or small crevices or cracks between two pieces of abutting steel which the acid bath can penetrate but not the molten zinc. This is covered in ASTM A385.

H. <u>FINISHES</u>

1. <u>Galvanizing</u>

Galvanized steel has found wide application for substation structures. Hot-dip galvanizing has been the most widely used finish on steel substation structures for the following reasons:

a. It is economical (initial cost, touch-up and general maintenance)

b. It provides good resistance to most corrosive environments

c. It has "self-healing" properties against minor abrasions

d. It requires little or no maintenance in most substation applications

New structures are galvanized in accordance with ASTM Standard Specification A123. Safeguards against embrittlement and warpage and distortion during galvanizing should be in conformance with ASTM Standard Specification A143 and A384, respectively. Galvanized members which are marred in handling or erection or which have had corrective work done should be touched up with a zinc rich paint.

All bolts and steel hardware should be galvanized in accordance with ASTM Standard Specification A153 for Class C material.

2. <u>Painting</u>

When painted structures are desired, there are several systems available. Consultation with reputable paint

suppliers is recommended. Painted structures may require periodic touch-up maintenance or repainting, depending upon severity of the environment and the quality of the work in the original application. One paint system which is applicable for substation structures is described here.

Surface Preparation:		The surface shall be thoroughly cleaned of all oil, grease, dirt, loose mill scale and other detrimental substances by solvent or mechanical cleaning.
Prime Coat	(a)	Carbon steel items should be primed with zinc yellow iron oxide base ready mixed paint conforming to Federal Specification TT-P-57B, Type 1.
	(b)	Galvanized items should be primed with zinc dust-zinc oxide primer conforming to Federal Specification TT-P-641D, Type II.
Intermediate Coat:		Exterior Enamel (tinted)
Finish Coat:		Exterior Enamel

Painted structures should be primed and receive the intermediate coat in the shop. The finish coat may either be applied in the shop or in the field. The finish coat can be applied under ideal conditions in the shop; however, the structure finish may be marred during shipment or erection requiring field touch-up. It is generally preferred to apply the finish coat in the shop and touch up as required.

3. Wood Preservatives

Wood preservatives for poles shall conform to that specified in REA Specification DT-5C (Electric).

All other timber shall be fully treated in accordance with REA Specification No. DT-5B (Electric) for Wood Crossarms, Construction Lumber and Pole Keys, and for Preservative Treatment of these Materials. Where framing and drilling are necessary for construction purposes, an approved preservative should be applied to the exposed untreated wood.

References

The American Society for Testing and Materials

A123 Standard Specification for Zinc (Hot-Galvanized) Coatings on Products Fabricated From Rolled, Pressed and Forged Steel Shapes, Plates, Bars and Strip

A143 Standard Recommended Practice for Safeguarding Against Embrittlement of Hot-Dip Galvanized Structural Steel Products and Procedure for Detecting Embrittlement

A153 Standard Specification for Zinc Coating (Hot-Dip) On Iron and Steel Hardware

A36 Standard Specification for Structural Steel

A325 Standard Specification for High-Strength Bolts for Structural Steel Joints, Including Suitable Nuts and Plain Hardened Washers

A384 Standard Recommended Practice for Safeguarding Against Warpage and Distortion During Hot-Dip Galvanizing of Steel Assemblies

A394 Standard Specification for Galvanized Steel Transmission Tower Bolts and Nuts

A307 Standard Specification for Carbon Steel Externally and Internally Threaded Standard Fasteners

A501 Standard Specification for Hot-Formed Welded and Seamless Carbon Steel Structural Tubing

The American Institute of Steel Construction

Specification for the Design, Fabrication and Erection of Structural Steel for Buildings

The American National Standards Institute

ANSI A58.1-1972 Building Code Requirement for Minimum Design Loads in Building and Other Structures

The American Welding Society

D1.1 Structural Welding Code

The Aluminum Association

Specifications for Aluminum Structures

Aluminum Standards and Data

The American Institute of Timber Construction

Timber Construction Manual

116 Guide Specifications for Structural Glued Laminated Timber for Electric Utility Framing

102 Standards for the Design of Structural Timber Framing

Federal Specifications and Standards

TT-P-57B Paint, Zinc Yellow-Iron Oxide-Base, Ready Mixed

TT-P-641D Primer Coating: Zinc Dust-Zinc Oxide (For Galvanized Surfaces)

Steel Structures Painting Council (SSPC) Specifications

SSPC-SP-1 Solvent Cleaning

SSPC-SP-2 Hand Tool Cleaning

The American Society of Civil Engineers

Electrical Transmission Line and Tower Design Guide

Design of Steel Transmission Pole Structures

U.S. Department of the Interior

Bureau of Reclamation Design Standard No. 10 Transmission Structures

The Uniform Building Code
The BOCA Building Code

National Electrical Manufacturers Association

TT1-1977 Tapered Tubular Steel Structures

CHAPTER VIII - FOUNDATIONS

A. GENERAL CONSIDERATIONS

Foundation design primarily depends upon the density or cohesive properties of the soil upon or in which foundations are located. The heterogeneous characteristics of soils make foundation design a much less exacting engineering problem than structural design or some facets of electrical design, but the inexactness of soil mechanics need not be a reason for ultraconservatism and costly foundations.

B. SOIL INFORMATION

1. General

A soil investigation should be conducted for each substation. Temporary installations and small distribution substations may only require a minimal amount of information. At these locations augered probe or vane shear tests (ASTM D2573) can be used to provide an indication of the soil characteristics.

Soil probes or borings should be taken primarily at critical foundations. These normally are for line support structures and transformers. The number of borings may vary from three at small substations to six or ten at larger substations. The depth of borings should be about 10 m (30 ft) below the final grade of the substation yard.

A sample specification for procurement of soil borings has been included as a part of this Chapter.

2. Soil Classification

Many times the Engineer whether to design the foundations as if the soil behaves as a cohesive soil or as a granular soil. The description of the material in the soil boring log should be described in accordance with the Unified Soil Classification System. (See Table VI-1 in Chapter VI).

Material described as "sandy clay" can, for example, be assumed to behave as cohesive material, whereas "clayey sand" will probably behave as granular material. The relative quantities of cohesive and granular materials can appreciably affect the soil properties and cause concern. Therefore, when in doubt, design the foundations both ways and use the most conservative design.

3. <u>Bearing Values</u>

The determination of bearing values and other structural values should be determined from appropriate sources such as text books, technical papers, etc., along with soil boring information. Soil analysis is not included in the scope of this document.

Soil bearing properties are frequently estimated on the basis of the standard penetration blow count values for granular soils and the unconfined compressive strength for cohesive or clayey soils.

4. <u>Ground Water Table</u>

Elevation of the ground water table is important in foundation design because excavation below it requires dewatering and increases costs. The water table also has considerable influence on the bearing capacity in granular soils. The bearing capacity of a footing in granular soil is derived from the density of the soil below the footing and the density of the soil surrounding the footing (backfill or surcharge).

The effect of the water table is to reduce the density of the granular soil because of buoyancy. The submerged density of granular soil is about half of the moist or dry density. If the water table is at or exceeds a depth equal to the footing width below the footing, the bearing capacity is not affected. If the water table is at the bottom of the footing, the portion of bearing capacity obtained by the density of soil below the footing is cut in half. If the water table is at the top of the backfill, the portion of bearing capacity obtained by the density of the surcharge is also cut in half.

5. <u>Differential Settlement</u>

Minor differential settlement between foundations in substations is generally acceptable. However, there are

certain soils and conditions which must be carefully reviewed and avoided if possible. Silts and silty sands are usually problem type soils. Weak stratas of soil under a thin layer of dense or good soil should be carefully examined and taken into consideration.

C. FOUNDATION TYPES

The various types of foundations, for substation structures and equipment, include augered piers, spread footings, piles, slabs on grade, rock anchors and direct embedment for wood or concrete poles.

1. Augered Pier

The augered pier is constructed by augering or drilling a hole in the ground, placing the rebar and filling with concrete. The anchor bolts may be cast in the pier at this time or set in a cap constructed at some later time, which is the usual practice.

When there is a sufficient quantity of foundations, the augered pier foundations are usually more economical than other types because of the "assembly line" installation procedure. Augured piers are most economical when soil conditions are not wet and sandy.

If wet and sandy soil is below a level where a spread footing would bear, the spread footing should be selected. However, if wet and sandy conditions also exist above the spread footing level, consideration should be given to the augered pier allowing extra costs for encasement. This design may be more economical than trying to install a spread foundation in wet, sandy soil.

Augered piers are best suited to resist overturning moments. Uplift and compressive type forces can also be adequately resisted by augered piers.

Common sizes for substation foundations range from 0.6 m (24 in) to 1.5 m (60 in) in diameter, in 150 mm (6 in) increments. Augered piers above 1.5 m (60 in) in diameter can be installed in 300 mm (12 in) increments with 2.5 m (96 in) being the maximum size used in normal substation applications.

The Engineer should attempt to utilize the same pier diameter for as many foundations as practical. Belling of the pier is rarely done for substation foundations.

For most substation equipment support structures and line support structures, the foundations are required to resist shear forces and overturning moments. For A-frame and lattice type line support structures, shear, uplift and compression are the design loads.

2. Augered Pier Design (Equipment Support Structures)

Equipment support structures designed by the working stress method having overturning moments at the column bases may be easily designed by a method developed by E. Czerniak and published in the "Journal of the Structural Division of the Proceedings of the American Society of Civil Engineers" in March 1957.

Convenient nomographs and soil values make the tedious formulas unnecessary. Some formulas are presented here for purposes of illustration and as an aid in design.

$$L^3 - 14.14 \frac{H_o}{R} L - 18.85 \frac{M_o}{R} = 0 \quad \text{for round piers VIII-1}$$

L: embedment length m, (ft)

H_o: lateral force per meter (foot) of pier diameter, in N/m (lbs/ft)

M_o: Moment per meter (foot) of pier diameter, applied at the resisting surface in m-N/m (ft-lbs/ft)

R: allowable lateral soil resistance, in newtons per square meter per meter of depth (pounds per square foot per foot of depth)

Lateral soil pressure (R) values for design are given in Table VIII-1

MATERIAL	VALUE	
	PSF/FT	N/m²/m
ROCK IN NATURAL BEDS - LIMITED BY THE STRESS IN THE PIER		
MEDIUM HARD CALICHE	500	78,500
FINE CALICHE WITH SAND LAYERS	400	62,800
COMPACT WELL GRADED GRAVEL	400	62,800
HARD DENSE CLAY	400	62,800
COMPACT COARSE SAND	350	55,000
COMPACT COARSE AND FINE SAND	300	47,100
MEDIUM STIFF CLAY	300	47,100
COMPACT FINE SAND	250	39,300
ORDINARY SILT	200	31,400
SANDY CLAY	200	31,400
ADOBE	200	31,400
COMPACT INORGANIC SAND AND SILT MIXTURES	200	31,400
SOFT CLAY	100	15,700
LOOSE ORGANIC SAND AND SILT MIXTURES AND MUCK OR BAY MUD	0	0

TABLE VIII-1 RECOMMENDED LATERAL SOIL PRESSURE (R)
(NEWTONS PER SQUARE METER PER METER DEPTH)
(POUNDS PER SQUARE FOOT PER FOOT DEPTH)

The maximum bending moment in the pier is obtained from the equation

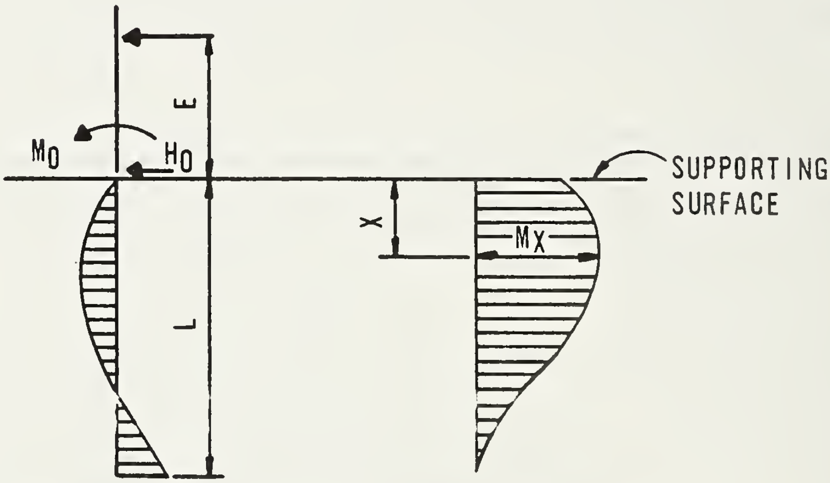
$$M_{max} = C_M H_o LD \qquad \text{VIII-2}$$

D: pier diameter, in m (ft)
C_M: moment coefficient

C_M the moment coefficient can be calculated from equation VIII-3 and Figure VIII-1 below or the maximum value can be obtained from Table VIII-2 below:

$$C_M = \left(\frac{E}{L} + \frac{X}{L}\right) - \left(\frac{4E}{L} + 3\right)\left(\frac{E}{L}\right)^3 + \left(\frac{3E}{L} + 2\right)\left(\frac{X}{L}\right)^4 \qquad \text{VIII-3}$$

where $E = \frac{M_o}{H_o}$ and X = distance from supporting surface to point of maximum bending moment (for the force diagram shown X = 0.35$\pm$)



FORCE DIAGRAM MOMENT DIAGRAM

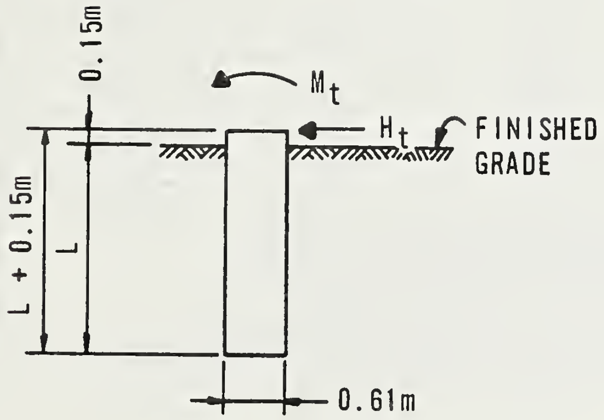
FIGURE VIII-1

E/L	0	0.25	0.5	0.75	1.0	1.25	1.5	1.75	2.0
C_M	0.26	0.48	0.70	0.92	1.16	1.40	1.64	1.88	2.12

TABLE VIII-2 MOMENT COEFFICIENTS

An augered pier foundation design example is illustrated for a bus support structure.

H_t = 2.27 kN M_t = 12.42 kNm assume $R = 39.3 kN/m^2/m$
$D = 0.61m$



$$M_o = \frac{M_t}{D} = \frac{12.42\ kNm + .15m\ (2.27\ kN)}{.61m} = \frac{20.92\ kNm}{m}$$

$$H_o = \frac{H_t}{D} = \frac{2.27kN}{.61m} = 3.72\ \frac{kN}{m}$$

$$E = \frac{20.92}{3.72} = 5.62\ m$$

$$L^3 - 14.14\ \frac{H_o L}{R} - 18.85\ \frac{M_o}{R} = 0 \qquad \text{VIII-1}$$

$$L^3 - 14.14\ \frac{(3.72)L}{39.3} - 18.85\ \frac{(20.92)}{39.3} = 0$$

L = 2.37m say 2.4 m

$$\frac{E}{L} = \frac{5.62}{2.4} = 2.3$$

interpolating $C_M = \frac{30}{25}\ (.24) + 2.12 = 2.41$

$M_{max} = C_M H_o LD = 2.41\ (3.72) 2.4\ (.61) = 13.1$ kNm

For this foundation use six 15.9 mm ϕ bars at equal spacing for reinforcement, see Tables VIII-3 thru 6. Use 9.55 mm ϕ bars for ties.

DIAMETER OF AUGERED PIER	6–15.9mm	6–19.1mm	6–22.2mm	6–25.4mm
30.5cm Φ	7.8	11.1	15.0	19.9
45.7cm Φ	14.6	20.7	28.2	37.1
61.0cm Φ	21.4	30.3	41.4	54.4
76.2cm Φ	28.1	39.9	54.5	71.7
91.4cm Φ	34.8	49.5	67.5	88.9
106.7cm Φ	41.6	59.1	80.7	106.2
121.9cm Φ	48.4	68.7	93.8	123.5

TABLE VIII-3 MAXIMUM MOMENT IN kN-m

FOR AUGERED PIERS WITH 6 STRAIGHT BARS

(F_y = 27.6 kN/cm2, f'_c = 2060 N/cm2)

(BASED UPON SIMPLIFIED WORKING STRESS ASSUMPTIONS)

DIAMETER OF AUGERED PIER	8–15.9mm	8–19.1mm	6–22.2mm	6–25.4mm
30.5cm Φ	11.4	16.3	22.1	29.2
45.7cm Φ	21.3	30.2	41.2	54.2
61.0cm Φ	31.0	44.2	60.2	79.3
76.2cm Φ	40.9	58.0	79.2	104.3
91.4cm Φ	50.7	72.0	98.2	129.3
106.7cm Φ	60.6	86.0	117.3	154.4
121.9cm Φ	70.4	99.9	136.3	179.4

TABLE VIII-4 MAXIMUM MOMENT IN kN-m

FOR AUGERED PIERS WITH 8 STRAIGHT BARS

(F_y = 27.6 kN/cm2, f'_c = 2060 N/cm2)

(BASED UPON SIMPLIFIED WORKING STRESS ASSUMPTIONS)

DIAMETER OF AUGERED PIER	6 - #5	6 - #6	6 - #7	6 - #8
12" Φ	5.75	8.2	11.1	14.7
18" Φ	10.8	15.3	20.8	27.4
24" Φ	15.8	22.4	30.5	40.1
30" Φ	20.7	29.4	40.2	52.9
36" Φ	25.7	36.5	49.8	65.6
42" Φ	30.7	43.6	59.5	78.3
48" Φ	35.7	50.7	69.2	91.1

TABLE VIII-5 MAXIMUM MOMENT IN FT-KIPS

FOR AUGERED PIERS WITH 6 STRAIGHT BARS (F_y = 40 KSI, f'_c = 3000 PSI)
(BASED UPON SIMPLIFIED WORKING STRESS ASSUMPTIONS)

DIAMETER OF AUGERED PIER	8 - #5	8 - #6	8 - #7	8 - #8
12" Φ	8.4	12.0	16.3	21.5
18" Φ	15.7	22.3	30.4	40.0
24" Φ	22.9	32.6	44.4	58.5
30" Φ	30.2	42.8	58.4	76.9
36" Φ	37.4	53.1	72.4	95.4
42" Φ	44.7	63.4	86.5	113.9
48" Φ	51.9	73.7	100.5	132.3

TABLE VIII-6 MAXIMUM MOMENT IN FT-KIPS

FOR AUGERED PIERS WITH 8 STRAIGHT BARS (F_y = 40 KSI, f'_c = 3000 PSI)
(BASED UPON SIMPLIFIED WORKING STRESS ASSUMPTIONS)

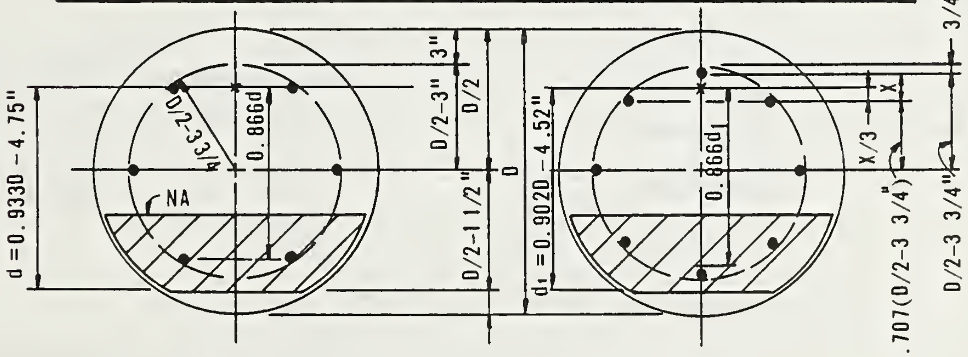
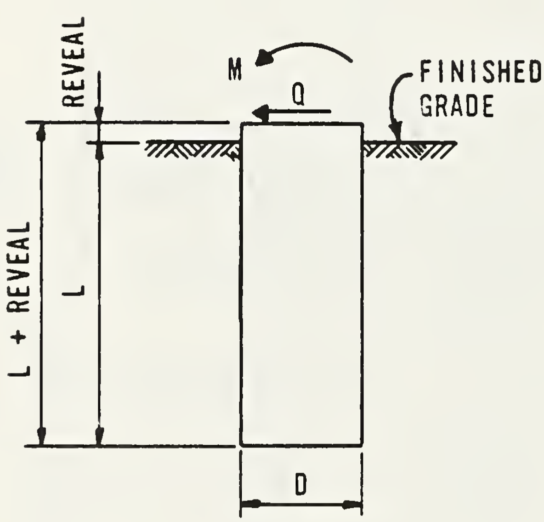


FIGURE VIII- 2

3. <u>Augered Pier Design (Line Support Structure)</u>

For pole type line support structure foundations, a different method of foundation design is employed. These structures are designed on the basis of yield stress and appropriate overload factors are applied to the structure loads. To compliment these loadings, a foundation design is used utilizing the ultimate strength of the soil. A very satisfactory method is illustrated, developed by Teng and Associates and based on the theory presented by B.B. Broms in the "Journal of the Soil Mechanics and Foundation Division of the Proceedings of ASCE." (Proceedings 3834, Volume 90, SM2, March 1964 and Proceedings 3909, Volume 90, SM3, May 1964.)

Some of this information is presented here as an aid in design.



k_p : coefficient of passive earth pressure

$= \tan^2 (45 + \phi/2)$

ϕ : angle of internal friction of soil $\approx 28.5^{o} + N/4$

γ : effective unit weight of soil, in kg/m^3 (pcf)

c : cohesive strength of soil, 1/2 unconfined compressive strength (q_u), in N/m^2 (psf)

N : number of blows per foot from standard penetration test

$H = M/Q$

q_u = Unconfined compressive strength $\approx N/4$

$q = Q/9CD$

For an augered foundation in cohesive soil use the following equations:

$$L = 1.5D + q\ [1 + \sqrt{2 + (4H+6D)/q}] \qquad \text{VIII-4}$$

$$M_{max} = M + 1.5\ QD + \frac{Q^2}{18CD} \quad @\ 1.5D + q \text{ below top of fdn} \qquad \text{VIII-5}$$

For augered foundations in granular soil use the equations:

$$L^3 - \frac{200\ QL}{k_p\gamma D} - \frac{200M}{k_p\gamma D} = 0 \quad \text{(Metric)} \qquad \text{VIII-6}$$

$$L^3 - \frac{2\ QL}{k_p\gamma D} - \frac{2M}{k_p\gamma D} = 0 \quad \text{(English)} \qquad \text{VIII-7}$$

$$\underset{\text{(bending)}}{M_{max}} = M + \frac{0.545Q\sqrt{Q}}{\sqrt{.010k_p\gamma D}} \quad @\ 0.817\sqrt{\frac{Q}{.010k_p\gamma D}} \text{ below grade} \qquad \text{VIII-8 (Metric)}$$

$$\underset{\text{(bending)}}{M_{max}} = M + \frac{0.545Q\sqrt{Q}}{\sqrt{k_p\gamma D}} \quad @\ 0.817\sqrt{\frac{Q}{k_p\gamma D}} \text{ below grade} \qquad \text{VIII-9 (English)}$$

The Engineer should utilize standard design procedures for determining the required area of reinforcing steel.

A foundation design using Brom's Theory for granular soil is illustrated below:
Design Example VIII-1:

Given:

$Q = 47.6$ kN $\qquad$ $D = 1.22$ m

$M = 535$ kNm $\qquad$ $N = 26$ blows/.3048 m

$\gamma = 1762\ kg/m^3$

$\phi = 28.5 + \frac{26}{4} = 35°$

$$k_p = \tan^2 (45° + 35°/2) = 3.69$$

$$L^3 - \frac{200(47.6)L}{3.69\ (1762)\ 1.22} - \frac{200(535 + .15 \times 47.6)}{3.69\ (1762)\ 1.22} = 0 \qquad \text{VIII-6}$$

L = 2.56 m + 0.15 m for reveal

L = 2.7 m

$$M_{max} \text{ in bending} = 535 + .15(47.6) + \frac{.545(47.6)\sqrt{47.6}}{\sqrt{.010(3.69)1762(1.22)}} = 562 \text{ kNm}$$

$$@\ 0.817 \sqrt{\frac{47.6}{.010(3.69)1762(1.22)}} = .63 \text{ m below grade}$$

4. Uplift and Compression (Augered Piers)

When designing augered pier foundations for loads which consist of uplift or compression, the type of soil (cohesive or granular) will govern the design philosphy employed.

The design of augered piers for uplift and compression is usually not a positive type of analysis. Many methods and procedures are presently used. Testing may be the only reliable approach. However, this is prohibitive for substations due to the high cost associated with it. More conservatism is required in the design for uplift and compression foundations.

a. Cohesive Soil

One approach that is used in cohesive soils is to assume that the uplift and compression forces acting on the pier are resisted by the shearing of the cohesive soil that is adjacent to the surface of the pier. The shear value used is one-half of the unconfined compressive strength of the cohesive soil. This would be an absolute maximum and should be tempered by some safety factor. Although an overload factor is already in the values being used for design, it is not uncommon to use an additional factor of safety for uplift. Depending on the completeness of the soil information, a maximum value of 1.5 may be used.

b. Granular Soil

Granular soils provide for the least positive analysis. Many involved approaches have been developed for granular soils. One, less refined but still used, is the inverted cone method. Testing of foundations has substantiated this approach as a reasonable design method. The variable characteristics of density, water table and questionable layers of soil require this method to also be employed with some conservatism.

This method assumes that the frictional resistance of the pier and soil will engage an inverted cone of earth. The angle which the sides of the cone make with the vertical axis of the pier is assumed to be from 20 to 30° depending on the density of the soil. The mass of the earth cone and the pier are assumed to resist the uplift.

5. Spread Footings

a. General

Spread footings comprised of a vertical pier or wall seated on a square or rectangular slab located at some depth below grade, have long been used in substation design.

They are usually preferred for transformers, brea kers, and other electrical equipment. They are economical where there are only a small quantity of foundations required. They are reliable and easy to design.

The installation time and costs for spread footings are more than for augered piers because of the excavation, forming, form stripping, backfilling and compacting.

Compaction of backfill around spread footings should at least be equal to that of the undisturbed soil before the footing was installed.

Spread footings should always be seated at a depth below the average frost penetration of the area. See Figure VIII-3.

Caution: The Engineer should determine if the average frost depth will be sufficient for the

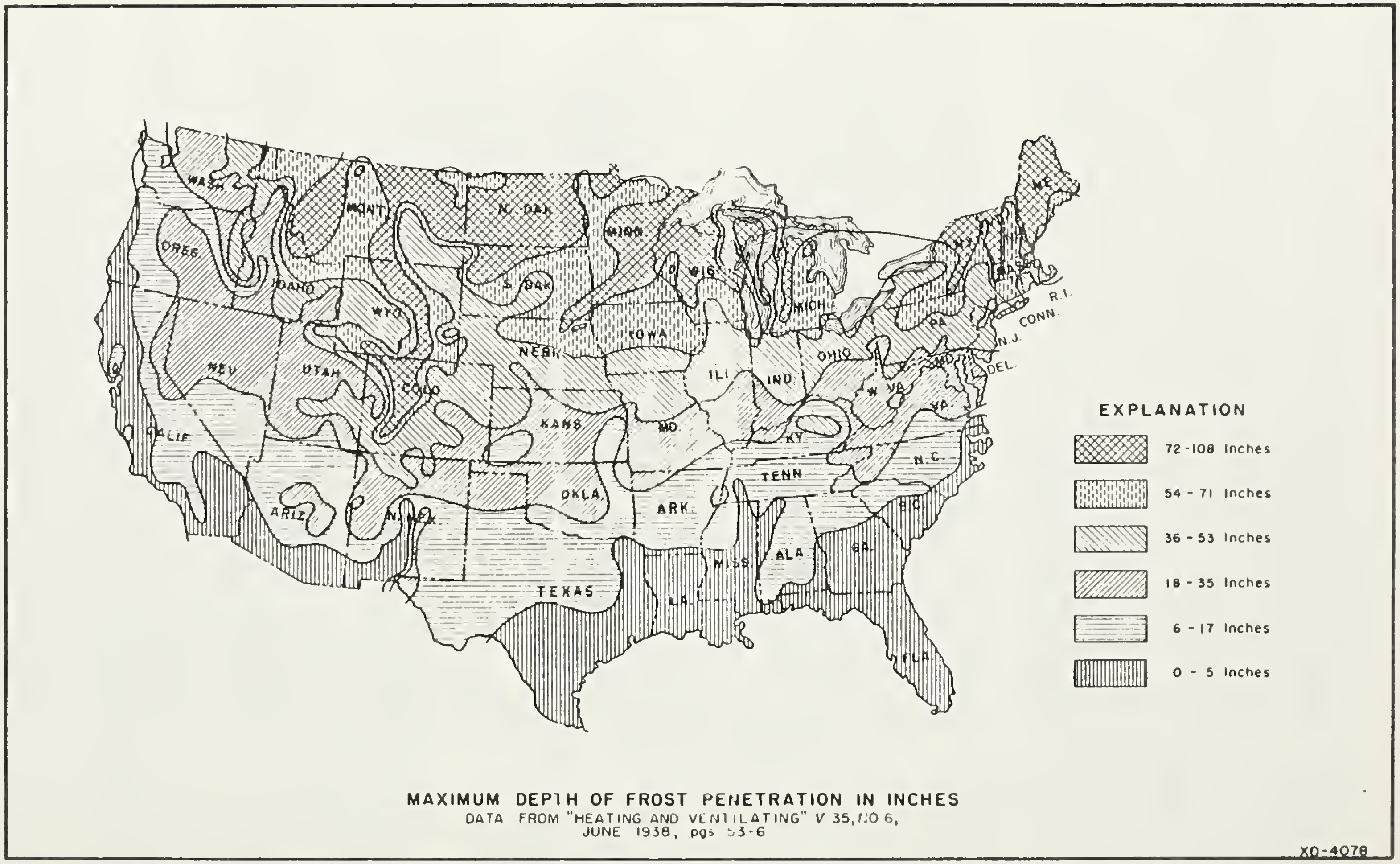


FIGURE VIII-3 MAXIMUM DEPTH OF FROST PENETRATION

prevailing conditions. Deeper footings may be warranted.

b. <u>Design for Compression</u>

In designing a spread footing for only downward loads, divide the total net load by the allowable soil bearing capacity and obtain the area of the footing required. Caution: In granular soils the water table location may have significant effect on the allowable soil capacity.

$$A = \frac{\text{Total Net Load}}{p} \qquad \text{VIII-10}$$

A: area of footing base, in m^2 (sf)

Total Net Load = LL + DL - Wt of displaced soil

LL: max weight or force exerted on footing by equipment or structure

DL: weight of foundation

p: allowable soil bearing pressure, in kg/m^2 (psf)

c. <u>Design for Uplift</u>

For the design of a spread footing for uplift only, the ultimate net uplift force (based on design loads times the appropriate OLF) should be exceeded by the weight of the foundation and the weight of the soil which rests directly on the slab. Several sizes may be selected before one is obtained which will result in the desired safety factor, 1.5 minimum. Caution: In granular soils, the water table location may reduce the weight of the soil being relied upon for uplift resistance.

d. Design for Moment

A spread footing subject to overturning may be designed as follows:

Assume: 1. All resistance to overturning is furnished by the vertical load, weight of the concrete footing and the weight of the soil block above the footing, the sum of which equals N.

2. The footing is rigid and tips about edge A.

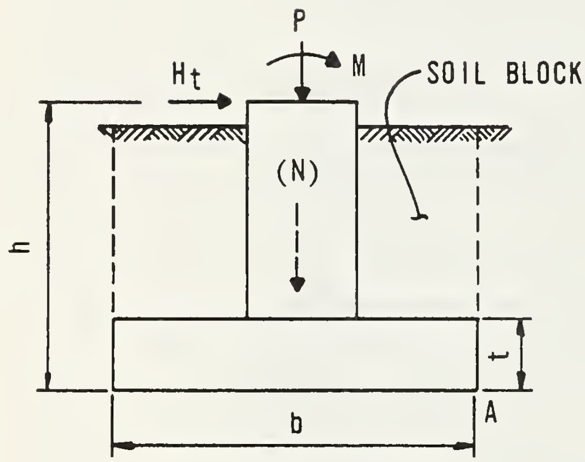


FIGURE VIII- 4a

$M_{ot} = M + H_t h$ (overturning moment)

$M_R = \frac{Nb}{2}$ (resisting moment)

$F.S. = \frac{M_R}{M_{ot}}$ between 1.5 and 2.0 is adequate for external stability

$$e = \frac{M_{ot}}{N}$$

Where e = eccentricity measured from the ¢, in m (ft),

M_{ot} = overturning moment

if $e < \frac{b}{6}$ $\quad p = \frac{N}{A} \pm \frac{M_{ot}}{S}$ VIII-11

p : actual soil pressure, in kN/m^2 (psf)

A : area of the footing, in m^2 (ft^2)

S : section modulus of the bottom of the footing about the axis which the moment is acting

$$S = \frac{db^2}{6}$$

d : width of footer, in m (ft)
b : length of footer, in m (ft)

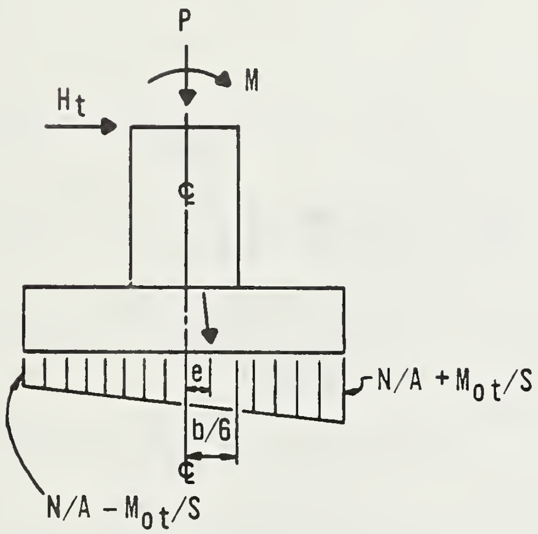
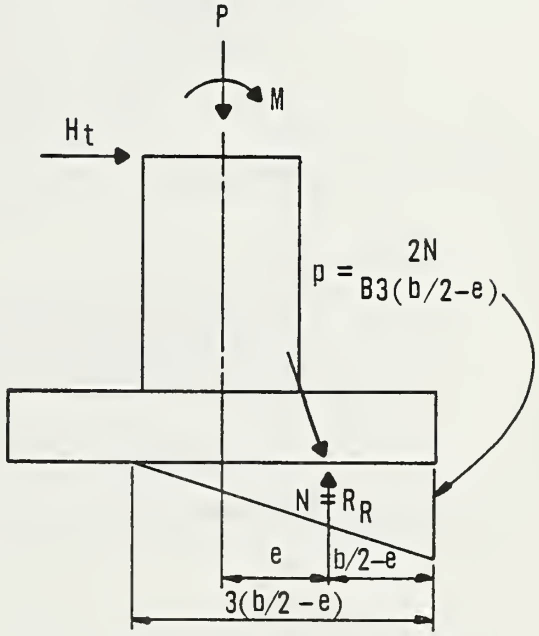


FIGURE VIII- 4b

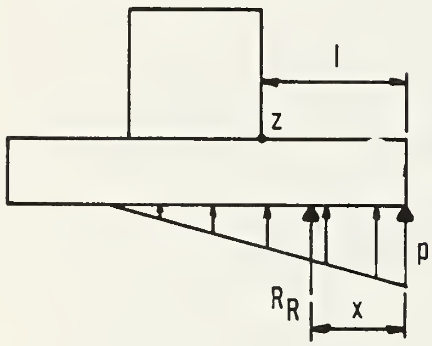
if $e > b/6$ $\quad p = \dfrac{2N}{B3(b/2 - e)}$

FIGURE VIII- 4c



Moments and shears are calculated for the concrete design of the slab and pier and conventional concrete design is employed to complete the design.

FIGURE VIII-4d



$$M_z = \left(p - \frac{\ell p}{3x}\right)\frac{\ell^2}{2} + \left(\frac{\ell p}{3x}\right)\frac{\ell^2}{3} \qquad \text{VIII-12}$$

$$V = \left(p - \frac{\ell p}{3x}\right)\ell + \left(\frac{\ell p}{3x}\right)\frac{\ell}{2} \qquad \text{VIII-13}$$

where M_z = bending moment about point z per unit width, in Nm/m (ft-lbs/ft)

= distance from toe of footer to bending point

x = distance from toe of footer to the resultant reaction R_R

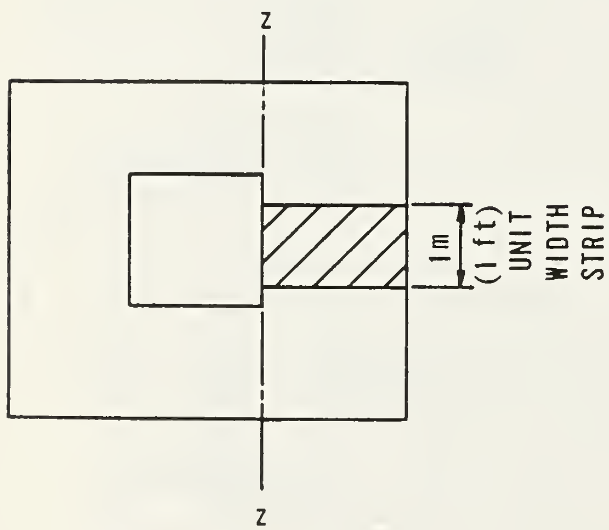


FIGURE VIII-4e

Design Example VIII- 2:

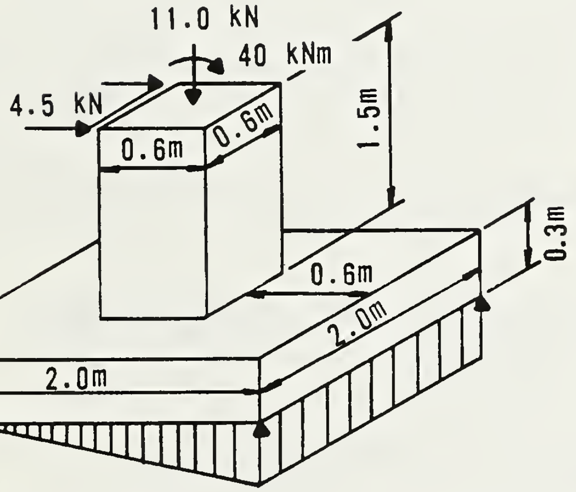
Given

1. Allowable bearing capacity of soil $= 140\ kN/m^2$

2. $M = 40$ kNm $H_t = 4.5$ kN $P = 11.0$ kN

3. $\gamma = 1600\ kg/m^3$ (assumed wt of soil)

Assume water table is very deep and is not a factor



weight of pier $= (.6m)^2 \times 1.5m \times 2400\ kg/m^3 =$ 1300 kg

weight of slab $= (2m)^2 \times .3m \times 2400\ kg/m^3 =$ 2880 kg

weight of soil $= (4m^2 - 0.36m^2) \times 1.35m \times 1600kg/m^3 =$ 7860 kg

weight of structure & equipment = (11.0 kN/9.8 N/kg)= 1120 kg

N = 13,160 kg

or 129,4 kN

Check for Overturning

$$M_{ot} = 40 \text{ kNm} + 1.8\text{m } (4.5 \text{ kN}) = 48.1 \text{ kNM}$$

$$M_R = 1\text{m } (9.8 \text{ N/kg})\ 13{,}160 \text{ kg} = 129.4 \text{ kNm}$$

$$\text{F.S.} = \frac{129.4 \text{ kNm}}{48.1 \text{ kNm}} = 2.7 > 1.5 \quad \text{okay}$$

Locate Resultant Force

$$e = \frac{48.1}{13.16(9.8)} = 0.37 \text{ m} > \frac{b}{6} = 0.33\text{m}$$

$$\text{therefore } p = \left(\frac{2}{3}\right) \frac{129.4 \text{ kN}}{(1\text{m}-.37\text{m})2\text{m}} = 68.5 \frac{\text{kN}}{\text{m}^2} < 140 \frac{\text{kN}}{\text{m}^2} \quad \text{okay}$$

Determine Bending Moment in Slab for use in calculating reinforcing steel

$$M = \left[68.5 \frac{\text{kN}}{\text{m}^2} - \frac{.6\text{m}}{3(1\text{m}-.37\text{m})} \times 68.5 \frac{\text{kN}}{\text{m}^2}\right] \frac{(.6\text{m})^2}{2} +$$

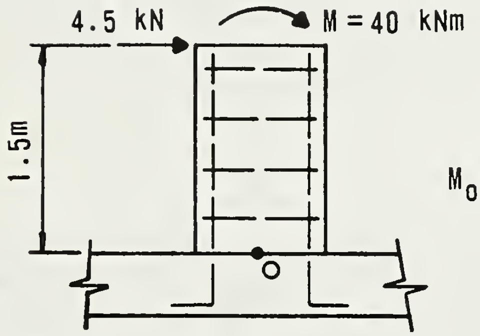
$$(.6\text{m})^2 \left[\frac{.6\text{m}}{3(1\text{m}-.37\text{m})} \times 68.5 \frac{\text{kN}}{\text{m}^2}\right] \frac{1}{2} \times \frac{2}{3}$$

$$M = 11.0 \text{ kNm}$$

The footing as shown above is slightly over designed. Additional trials could be made to reduce the size, if desired. Other steps for completing the reinforced concrete design should be completed by the Engineer.

Determine Bending Moment in Pier for use in calculating reinforcing steel

Assume that the pier is a vertical cantilever beam



$$M_0 = 40 \text{ kNm} + 1.5\text{m}(4.5 \text{ kN}) = 46.8 \text{ kNm}$$

6. Slabs on Grade

a. General

Slabs on grade are sometimes used as foundations for miscellaneous equipment supports, switchgear, breakers and power transformers. Slabs on grade should be used with caution where there is a chance of frost heave. This may cause problems with equipment which has rigid bus connections or in some other way may result in an operational malfunction of the equipment.

Slabs on grade may be satisfactory in frost prone climates if the subgrade is essentially granular and well drained.

b. <u>Subgrade Preparation</u>

An important part of the installation of a slab on grade is the preparation of the subgrade. The soil should be thoroughly mixed and compacted to provide a nearly homogeneous, firm bearing surface. Proper preparation may help prevent objectionable settlement.

Slabs usually vary in thickness between 30 and 60 cm (12 and 24 in) depending on the various design parameters. The slab should bear on the prepared subgrade and not on site stone or stone in oil retention sumps.

c. <u>Jacking Loads</u>

Transformer slabs are sometimes designed for "jacking loads" as well as "in-place" loads. "Jacking loads" impose considerably different and larger stresses in the parts of the slab that are barely stressed at all from "in-place" loads. The engineer should determine if jacking load design criteria is desirable because it usually increases the size and reinforcing of the slab foundation. Soil bearing pressures shoul be kept low. Usually between 48 and 72 kN/m^2 (1000 and 1500 psf) is a reasonable range. Higher pressures will occur from jacking loads but only for a relatively short time.

Design Example VIII-3:

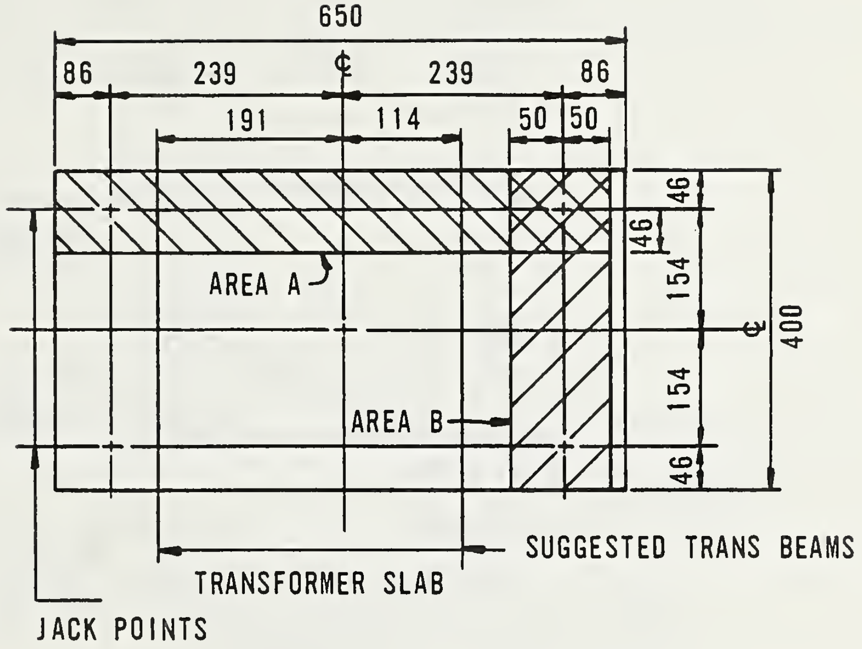
Design a transformer slab based on the following assumptions:

161/13.2 kV transformer	weight	110,900 kg
	oil	58,060 kg
		168,960 kg

extreme base dimensions 584 cm x 320 cm
jack lugs located 239 cm from of fdn
and 154 cm from of fdn

1st trial size of slab 650 cm x 400 cm x 60 cm

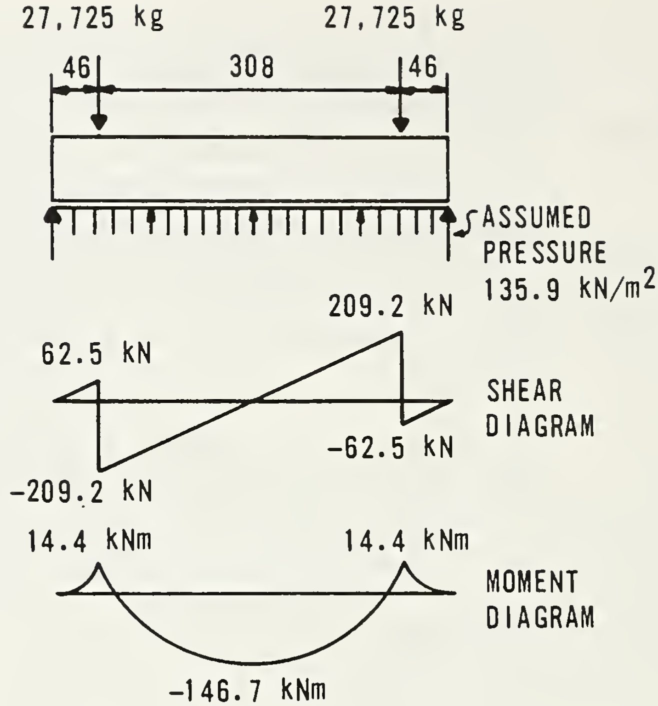
$$\text{soil pressure} = \frac{168{,}960 \text{ kg}}{6.5 \text{ m} \times 4.0 \text{ m}} \times 9.8 \text{ N/kg} = 63.7 \frac{\text{kN}}{\text{m}^2} \quad \text{okay}$$



Jacking Loads

The transformer weight (less oil) is assumed to act as equal point loads at all jacking locations. These loads are assumed to act upon strips of the slab (approximately 100 cm) as shown by Areas A and B. In many other instances it may be desirable to use the total transformer weight (including oil and radiators).

The analysis of Areas A and B can be made using shear and moment diagrams, shown for Area B in the following sketch.



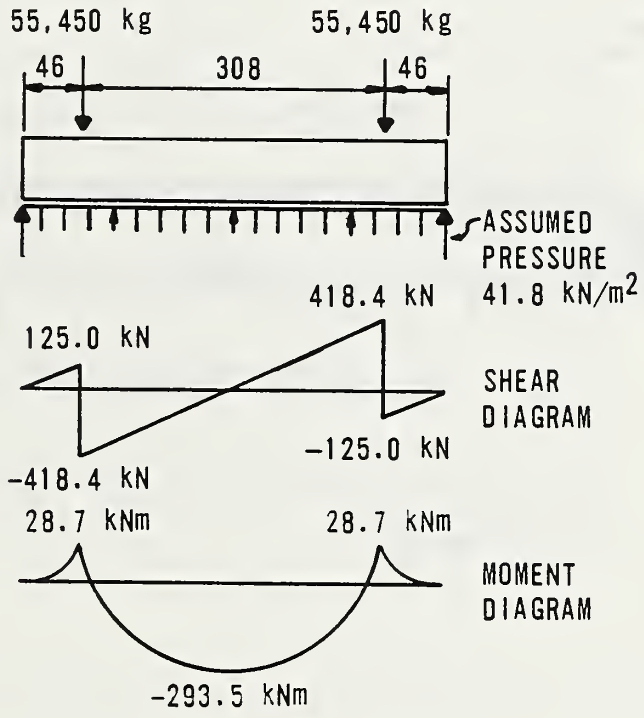
AREA B = (100 cm x 400 cm)

M_{MAX} = 146.7 kNm

Remaining design of reinforcing steel and other calculations in concrete design should be completed by the Engineer.

Top Steel (Between "B" Strips)

For the design of the remainder of the top steel, assume that the jacking loads are resisted uniformly by the entire slab, as shown below.

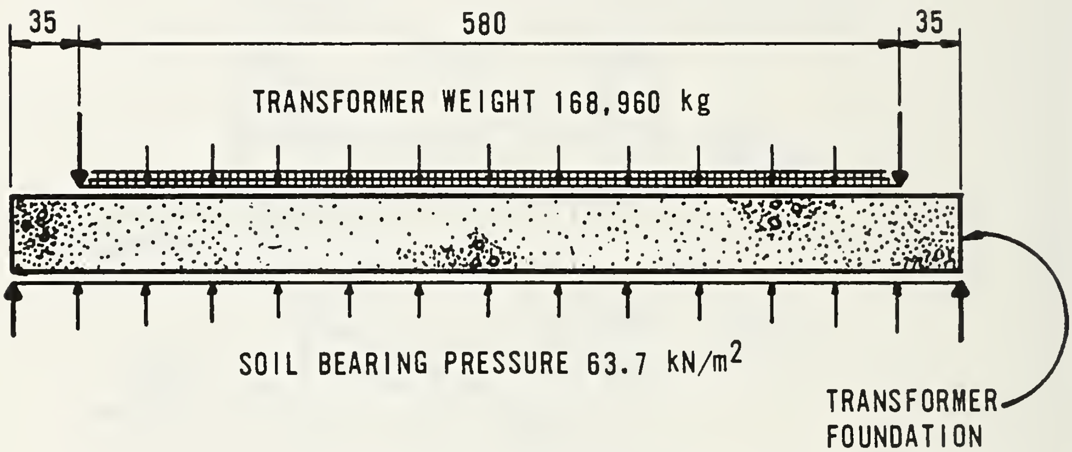


$M_{MAX} = 293.5$ kNm

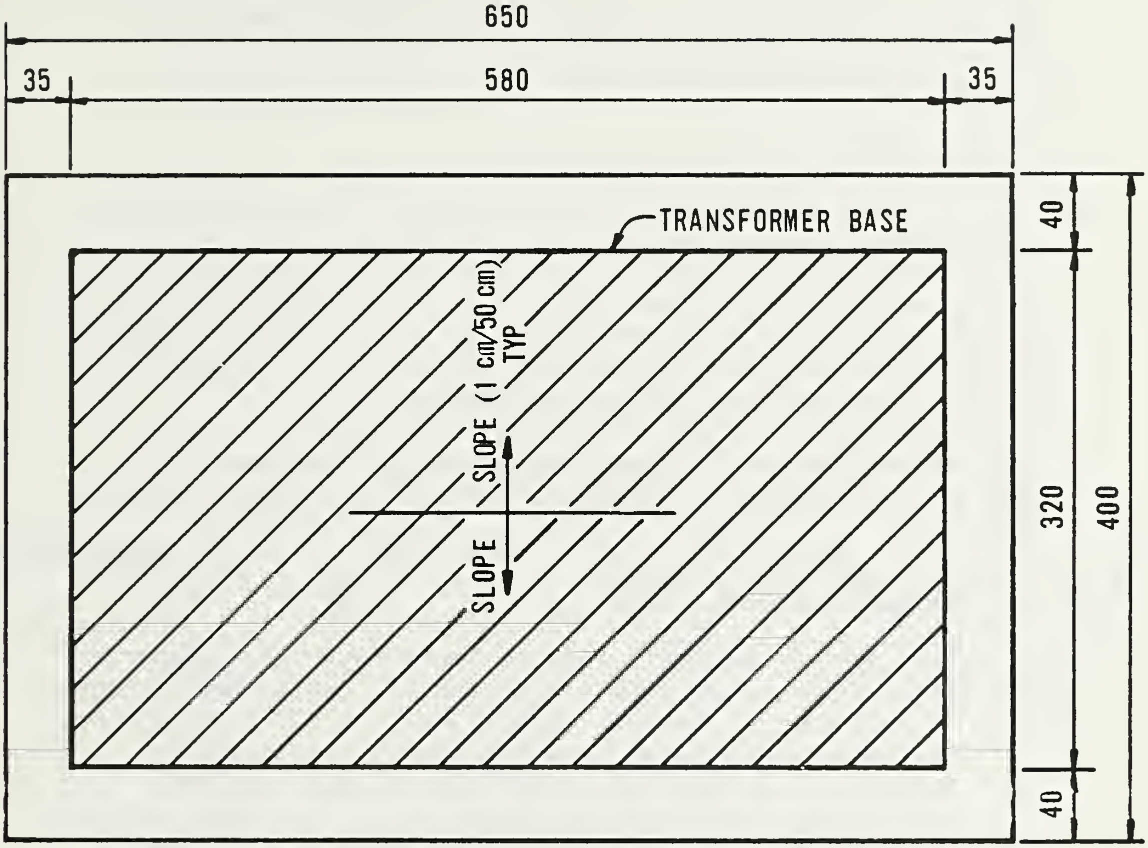
The reinforcing steel in the long direction for Area A and that in between the "A" strips is computed in a similar manner.

Analysis for Transformer in Place

The analysis of the foundation for the in place transformer is calculated as follows, using the transformer weight plus oil:



The remaining reinforced concrete design should be completed by the Engineer.



The bending moment for the in-place condition is easily computed by taking moments about the edge of the transformer base.

$$M = \frac{.4m^2}{2} \times 63.7 \ \frac{kN}{m^2} \times 6.5m = 66 \text{ kNm (very low)}$$

Although temperature steel requirements may control for the bottom reinforcing in each direction, it is advisable to place more reinforcing in the slab.

There may be impact forces induced when installing or removing the heavy transformer. Conservatism in transformer slab design should be adhered to in view of the critical nature and high cost of the transformers.

D. OIL POLLUTION

Oil pollution from transformers and other substation equipment is discussed in Chapter II.

If oil pollution abatement is necessary, the degree of reliability that is desired must be decided. The primary function of all systems is to prevent oil from reaching prohibited areas, including the ground water table.

A determination must be ascertained if the system will be self-operating or must be monitored on a periodic or seasonal basis.

1. Basic Retention System

This system should include an impervious lined, open or stone filled sump area around the oil containment vessel (transformer). Usually stone 5 to 9 cm (2" to 3-1/2") is desirable in the sump area, to enable operators and maintenance personnel easy access to and around the transformer. The size and gradation of the stone affects the percent of voids available to store oil. Stone of the size mentioned above may provide 25 to 40 percent voids. Perforated pipe placed in the bottom of the sump will convey, by gravity flow, water and oil to an underground storage tank. The tank must have a sump pump to periodically pump out the water which has collected from rainfall. The pump may be regulated to cut on and off by a float valve, or pressure switches. The transformer also should have a low oil level alarm which deactivates the sump pump.

At the cut-off position, there should be at least six inches of water covering the bottom of the tank. This enables small or slow oil leaks to be stored on top of the water. The storage tank should be designed to retain all of the oil in one transformer between cut-off water level and inlet pipe.

The oil is removed from the tank by pump trucks.

The system is costly but reasonably reliable. Mechanical failure of the sump pump is a disadvantage.

2. <u>Oil Separator Tank</u>

This system is feasible only where there is sufficient gradient for gravity discharge from the underground tank. See Figure VIII-5.

The oil or water is collected from the transformer area as it was in the basic retention system. It is discharge into an oil separator tank. The principle upon which this system operates is that oil is lighter than water and floats upon it.

The oil separator tank should be designed to contain all of the oil in one transformer should a major rupture occur. This system allows the water to continuously pass through but retains the oil. The oil retained in the tank must be pumped into a tank truck and disposed of.

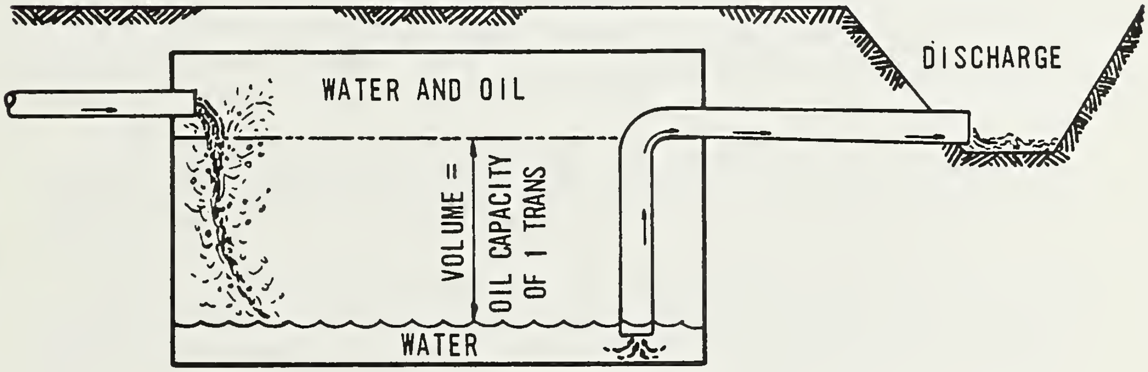


FIGURE VIII-5

This system is costly but quite reliable.

The oil separator tank principle may be applied to above grade diked basins where freezing temperatures are not prevalent.

Modification to the above grade separator system may be considered when regular inspection is anticipated. It could consist of a transformer area that is lined and diked with impervious material. A short piece of four inch pipe passes through the dike and contains a shut-off valve which may either be:

a. left open for continuous drainage and closed in an emergency when alarms or inspection indicates

b. Closed and opened as necessary to drain the collected water at periodic inspections

This system is relatively economical but contains several unreliable features.

3. Summary

Each solution to the oil abatement problem is not without its own problems. These should be evaluated along with system costs when making the decision for the most desired system at each substation.

SPECIFICATION
FOR
PROCURING
SOIL BORINGS

1. SCOPE

1A. The work shall consist of making soil borings to determine nature and extent of the soil strata at the ____________ Substation near ______________, ________________. Laboratory testing will be required on undisturbed samples as outlined in the Specifications. Drawing _____________ is a part of this Specification.

2. GENERAL

2A. The Contractor shall furnish all necessary equipment, materials, and labor to make the borings at the locations shown on Drawing _________________.

2B. The Contractor shall be responsible for all damage to public and private property resulting from the operations of his employees.

2C. The Contractor shall also comply with all Federal, state and local rules and regulations with regards to permits, bonds, drilling, plugging and all other applicable aspects of well drilling.

3. WORKMANSHIP AND METHODS

3A. Borings shall be taken by the Contractor at the locations previously staked in the field and as shown on the Drawing.

3B. In soil which is predominantly cohesionless, make the standard penetration test in accordance with ASTM Specification D1586. Use a 2" O.D. x 1-3/8" I.D. split tube sampler and 140 lb weight falling free at 30". Record the number of blows per 12" of penetration at each change in stratification or character of the soil but at intervals not exceeding 3' for the first 15' and at 5' intervals thereafter.

3C. In soil which is predominantly cohesive, use the thin-walled tube method for sampling in accordance with ASTM Specification D1587. Take samples in each change of stratification but at intervals not exceeding 3' for the first 15' and at 5' intervals thereafter.

3D. Boring in hard strata or rock shall be performed by diamond coring in accordance with ASTM D2113.

3E. The depth of borings is indicated on the attached Drawing. If boulders or materials are encountered which prevent penetration to the required depth, the location of the boring shall be changed a maximum of 10' for a second boring. If refusal occurs on the second boring in less than 15', the boring shall be considered complete.

3F. The Contractor shall be cognizant of the fact that borings are being obtained for foundation design information. If it becomes apparent during the boring operation that the material throughout the depth of the borings is unusually soft or the standard penetration values are very low so that it might appear that piling might be necessary, the Contractor shall so inform the proper authority, in this case, Mr. ____________ who may be reached at _________________. The Contractor shall not leave the site until he is further notified of what action is desired. Such notification is not anticipated to take more than one-half day.

4. FINAL REPORT

4A. Four copies of the final report shall be mailed to Mr.______________ not later than two weeks after the drilling operations have been completed.

4B. The Contractor's report shall include the following:

(1) Project identification, boring number, location and driller.

(2) Depth of topsoil.

(3) Elevation of ground water at completion of boring and also 24 hours after completion, including dates and times measured.

(4) Vertical plot sections, referred-to datum, showing type and descriptive classification of material encountered and the upper boundary elevation of each successive soil strata. Descriptive classification shall include group symbol of the Unified Soil Classification System.

(5) Number of blows per 12" penetration from standard penetration test.

(6) Dry density of soil and moisture content.

(7) Unconfined compressive strength tests on all cohesive soils procured from the samples.

(8) Date of beginning and end of boring.

(9) If it is necessary to stop boring or move a hole due to obstruction, breaking of casing, etc, it shall be noted and properly described.

REFERENCES

Journal of the Structural Division, Proceedings of the American Society of Civil Engineers, Resistance to Overturning of Single, Short Piles, E. Czerniak, March, 1957

Journal of the Soil Mechanics and Foundations Division, Proceedings of the American Society of Civil Engineers, Tapered Steel Poles Caisson Foundation Design, B.B. Broms, 1964-1965

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CHAPTER IX - GROUNDING

A. GENERAL

An effective substation ground system typically consists of driven ground rods, buried interconnecting grounding cables or grid, equipment ground mats, connecting cables from grid to metallic parts of structures and equipment, connections to grounded system neutrals, and the ground surface insulating covering material. The functions of the grounding system are: a system function for the proper operation of electrical equipment and a personnel safety function.

The system function is served by providing the lowest practical resistance between circuit neutrals and true earth. This is to help insure proper operation of protective relays and to limit the voltage to ground that can appear on unfaulted phases when one phase is faulted to ground. Many years ago the system function was often considered the governing factor in determining required maximum ground system-to-earth resistance. Typically, resistance values were established calling for major substations to have resistances in the order of one ohm. Less important substations could have a higher resistance. More recently, personnel safety requirements have been found to govern. Experience now shows that, on an electrical system which is "effectively grounded," a substation ground system which is safe will also be satisfactory for system functions. (See Chapter V, Section H for definition of an "effectively grounded" system.)

The second major function of grounding systems, personnel safety, is more complex. Currents flowing into the ground grid from lightning arrester operations, impulse or switching surge flashover of insulators, and line-to-ground fault currents from the bus or connected transmission lines, all cause potential differences between grounded points in the substation and remote earth. Without a properly designed grounding system, large potential differences can exist between different points within the substation itself. Under normal circumstances, it is the current flow through the ground grid from line-to-ground faults that constitutes the main threat to personnel.

It should be recognized that there is no overall record of injuries that resulted from deficient grounding systems.

Equally, however, it should be appreciated that with more substations being built, higher fault currents become possible. Therefore, it is becoming more important to protect against personal injury and equipment damage.

While line-to-ground faults may result in currents of thousands of amperes lasting several seconds, modern relay systems reduce the fault duration to a few cycles. During fault current flow, a low ground grid resistance to remote earth, although desirable, will not, in itself, necessarily provide safety to personnel. It is necessary that the entire grounding system be designed and installed so that under reasonably conceivable circumstances, personnel are not exposed to hazardous potential differences across the body.

Designing a proper substation grounding system is a complicated task. Numerous parameters affect its design, and it is often difficult to obtain accurate values for some of these parameters. Furthermore, temperature and moisture conditions can cause extreme variations in the actual resistivity of the ground in which the system is installed. Methods of dealing with the design problem are necessarily based to some extent on approximations and the exercise of informed judgement. The design approach must be conservative because of the aforementioned uncertainties.

For reference material IEEE Standard 80, "Guide for Safety in Substation Grounding," is generally recognized as one of the most authoritative guides available. It is recommended for any person concerned with the design of substation ground systems. A bibliography in the IEEE guide lists important additional references, including abstracts of many of them. The Bibliography at the end of this chapter lists references not included in IEEE 80.

This chapter will describe some of the different modes in which ground fault current may flow with respect to substation grounding systems. Included is discussion of safety considerations in and near substations when all or a portion of this fault current flows through the substation grounding system. Specific recommendations for the design, installation and testing of safe and effective grounding systems for REA substations are included.

B. GROUND FAULT CURRENTS

When a substation bus or transmission line is faulted to ground, the flow of ground current in both magnitude and direction

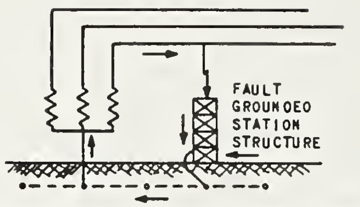
depends on the impedances of the various possible paths. The flow may be between portions of a substation ground grid, between the ground grid and surrounding earth, along connected overhead ground wires, or along a combination of all these paths.

The relay engineer is interested in the current magnitudes for all system conditions and fault locations so that protective relays can be applied and coordinating settings made. The designer of the substation grounding system is interested primarily in the maximum amount of fault current expected to flow through the substation grid, especially that portion from or to remote earth, during the service lifetime of the installed design.

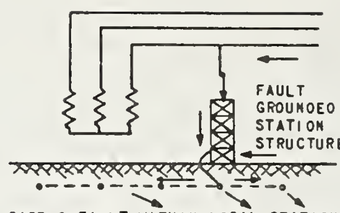
Figure IX-1 illustrates some of the cases governing ground fault current flow. The worst case for fault current flow between the substation grounding grid and surrounding earth in terms of effect on substation safety must be determined. The maximum symmetrical rms fault current at the instant of fault initiation is usually obtained from a network analyzer study or by direct computation. This current is then modified by a correction factor (see Table IX-1) to account for the effect of dc offset and ac and dc decrements. The resulting current is the effective current during a given time interval after fault initiation. It is based on assuming 100 percent offset of the current wave at time of fault inception and applying reasonable attenuation factors to the ac and dc components of the current wave. Explanation of the method of determining attenuation factors may be found in IEEE Std 320, Application Guide for AC High Voltage Circuit Breakers Rated on a Symmetrical Current Basis (ANSI C37.010). The resulting effective current should be increased a reasonable amount to allow for future system growth.

TABLE IX-1
Fault Current Correction Factor

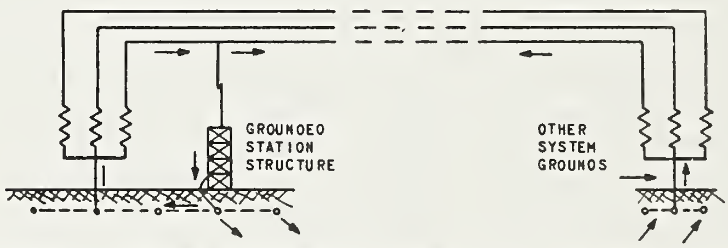
Shock and Fault Duration t		Decrement Factor D
Second	Cycles (60 Hz ac)	
0.008	0.5	1.65
0.1	6	1.25
0.25	15	1.10
0.5 or more	30 or more	1.00



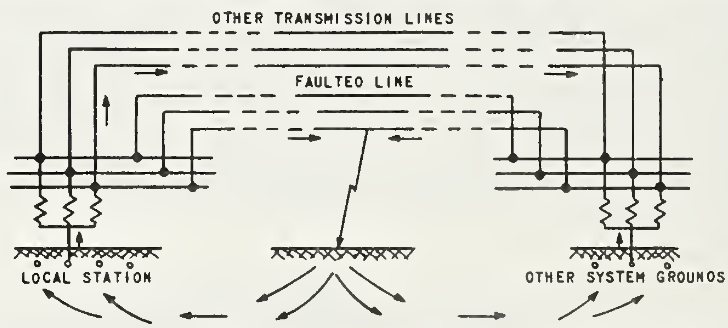
CASE 1-FAULT WITHIN LOCAL STATION. LOCAL NEUTRAL GROUND ONLY. FAULT CURRENT FOLLOWS METALLIC PATH PROVIDED BY GROUND GRID. NO APPRECIABLE CURRENT FLOW IN EARTH.



CASE 2-FAULT WITHIN LOCAL STATION. NEUTRAL GROUNDED AT REMOTE LOCATION ONLY. TOTAL FAULT CURRENT FLOWS FROM STATION GROUND GRID TO EARTH.



CASE 3-FAULT IN STATION. SYSTEM GROUNDED AT LOCAL STATION AND ALSO AT OTHER POINTS. FAULT CURRENT RETURNS TO LOCAL NEUTRAL THROUGH LOCAL GRID AND TO REMOTE NEUTRALS THROUGH THE EARTH. LATTER IS THE COMPONENT OF CONCERN IN STUDY OF DANGER VOLTAGES.



CASE 4-FAULT ON LINE OUTSIDE STATION. SYSTEM GROUNDED AT LOCAL STATION, AND ALSO AT OTHER POINTS. PORTION OF FAULT CURRENT RETURNING FROM EARTH TO GROUND GRID AT LOCAL STATION DETERMINES GRID POTENTIAL RISE AND GRADIENTS THERE.

CASES 1, 2 AND 3 SHOW FAULTS WITHIN LOCAL STATION. CASE 4 SHOWS FAULT ON LINE OUTSIDE LOCAL STATION.

FIGURE IX-1

TYPICAL GROUND FAULTS

In most cases, fault current studies using only the system reactances (formula 8, IEEE-80) and neglecting system resistances will provide sufficiently accurately valves of the initial fault current. Where resistances are appreciable and included in the studies (formula 7, IEEE-80), more accurate values of fault current are obtained. In this case, the contribution through the substation ground grid can be estimated from formula 11 (or formula 20 for greater accuracy), IEEE-80.

Formula 7 from IEEE-80:

$$I'' = \frac{3E}{3R + 3R_f + (R_1 + R_2 + R_0) + j\,(X_1'' + X_2 + X_0)} \text{ amperes} \qquad \text{IX-1}$$

Formula 8 from IEEE-80:

$$I'' = \frac{3E}{X_1'' + X_2 + X_0} \text{ amperes} \qquad \text{IX-2}$$

where:

I'': Symmetrical rms value of ground-fault current, at instant of fault initiation, in amperes.

E: Phase-to-neutral potential, in volts.

R: Estimated resistance to earth of local substation ground system, in ohms.

R_f: Estimated minimum resistance of the fault itself, in ohms.

R_1: Positive-sequence resistance, ohms per phase.

R_2: Negative-sequence resistance, ohms per phase.

R_0: Zero-sequence resistance, ohms per phase.

X_1'': Direct-axis positive-sequence reactance (sub-transient), ohms per phase.

X_2: Negative-sequence reactance, ohms per phase.

X_0: Zero-sequence reactance, ohms per phase.

Formula 11 from IEEE-80:

$$R = \frac{\rho}{4r} \tag{IX-3}$$

Formula 20 from IEEE-80:

$$R = \frac{\rho}{4r} + \frac{\rho}{L} \tag{IX-4}$$

where:

R: Station ground resistance, in ohms.

ρ: Average ground resistivity, in ohm-meters.

r: Radius of a circle having the same area as that occupied the ground grid, in meters.

L: Total length of buried conductor (including ground rods), in meters.

C. SAFETY CONSIDERATIONS

Under ground fault conditions, the portion of fault current flowing between a substation ground grid and the surrounding earth will result in potential gradients within and around the substation. Unless proper precautions are taken in design, the maximum gradients present can result in a potential hazard to a person in or near the substation. In addition to the voltage magnitude of the local gradients, such things as duration of the current flow, impedances in its path, body resistance, physical condition of the person and probability of contact, all enter into the safety considerations.

1. Tolerable Limits of Body Current

The threshold of perception for the human body is about one milliampere at commercial (50 or 60 Hz) frequencies. Higher currents (about 6-25 mA) can result in painful situations and affect the muscles so that the energized object cannot be released (let-go-level). Higher mA currents can affect breathing and may cause fatalities if duration (usually in the order of minutes) is long enough. Further current increases (about 50 mA and above) can result in ventricular fibrillation of the heart. Currents above the level for ventricular fibrillation can cause heart paralysis, inhibition of breathing and burns.

Rea Bulletin 62-4 contains additional information on electric current effects.

Since currents of a magnitude that exceed let-go-level can affect breathing, they must be avoided if the duration is likely to be long. Fortunately, in most situations in substations, the protective relays will prevent any fault from lasting that long. Therefore, it is usually those levels of current that can lead to ventricular fibrillation that form the basis for most potential gradient limitation efforts. The tolerable level is related to the duration of current flow through the body by the following formula:

$$I_k = \frac{0.116}{t^{1/2}} \qquad \text{IX-5}$$

I_k: Rms current through the body, in amperes.

t: Time duration of current flow, in seconds.

The above formula is considered applicable to perhaps 99.5 percent of all 50 kg (110 lb) persons for shock durations within the range of 0.03 to 3.0 seconds. It is based on limiting the total watt-seconds of energy, I_k^2t, absorbed in a person's body (with an assumed weight of 50 kg (110 lb) during the shock.

2. Tolerable Potential Differences

Using the limits of tolerable body currents for prevention of ventricular fibrillation and appropriate circuit constants, tolerable potential differences can be determined. Essentially all situations for potential differences during fault current flow can be described by "step," "touch" or "transferred" potentials.

a. Step Potentials

Step or foot-to-foot contact is shown in Figure IX-2. Here, the potential difference shunted by the body is considered as limited to the maximum value between two accessible points on the ground, separated by one meter (equal to one space or one "step"). The parameters in Figure IX-2 are defined below and followed by the development of an equation for calculating tolerable step potentials.

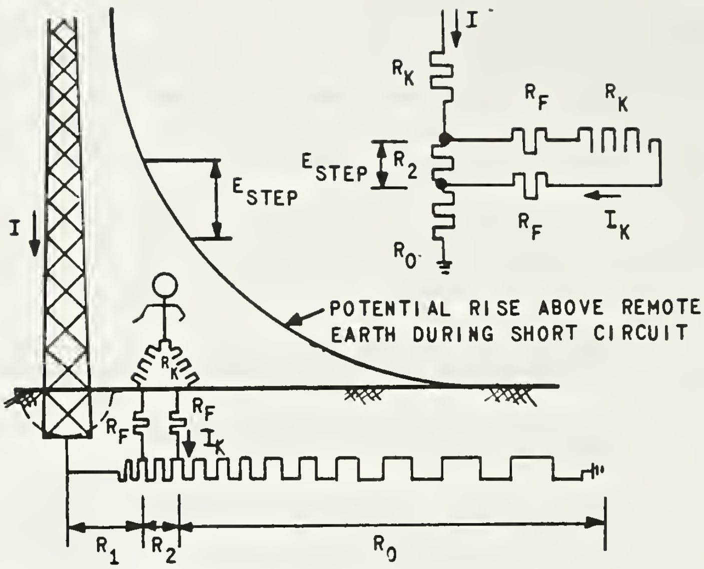


FIGURE IX-2 STEP POTENTIALS
NEAR GROUNDED STRUCTURE

Parameters of Figure IX-2:

$(R_1 + R_2 + R_0)$ equals the resistance, in ohms, of the grounding system from the affected structure to remote ground. The sum of R_1, R_2 and R_0 is discussed later in Paragraph C2d.

R_F is the combined resistance, in ohms, of each shoe and of the ground immediately under each foot. Since shoe resistance is uncertain, it is usually neglected in calculations and R_F equals only the contact resistance of $3\rho_s$.

R_k is the body's resistance to current flow, usually taken as 1000 ohms.

I is the portion of the total fault current, in amperes, flowing from the metallic structure into the grounding grid and then into the ground.

I_k is the tolerable current (to prevent ventricular fibrillation), in amperes, flowing through the body from foot-to-foot, based on $I_k = \frac{0.116}{t^{1/2}}$

ρ_s is the resistivity of the surface material. IEEE 80 indicates that a value of 3,000 ohm-meters may be conservative for a 10 cm (4 in.) thick coarse, crushed rock layer even when wet. "Site Design," Chapter VI, offers guidelines for the specification of such surface material where required. IEEE research is continuing on the total subject of grounding. More accurate values for ρ_s may become known for various materials, surface thicknesses and gradations. Current IEEE information should be consulted.

E_{step} is the allowable potential.

<u>Equation for E_{step}:</u>

$$E_{step} = (R_k + 2R_F)\, I_k \qquad \text{IX-6}$$

$$E_{step} = (1000 + 6\rho_s)\, \frac{0.116}{t^{1/2}} \qquad \text{IX-7}$$

$$E_{step} = \frac{116 + 0.7\ \rho_s \text{ volts}}{t^{1/2}} \qquad \text{IX-8}$$

If a good layer of crushed rock or equivalent material, 10 cm (4 in.) minimum is recommended, is present, ρ_s = 3000 ohm-meters and

$$E_{step} = \frac{116 + 0.7 \times 3000}{t^{1/2}} \qquad \text{IX-9}$$

$$E_{step} = \frac{2216}{t^{1/2}} \qquad \text{IX-10}$$

For a given duration of shock current, in seconds, the allowable E_{step}, determined from the above formula, is shown in Table IX-2.

Table IX-2

Allowable E_{step} for Given Duration of Shock Current

Shock Duration, t Seconds	Cycles	E_{step}, Volts
0.1	6	7,000
0.2	12	4,950
0.3	18	4,040
0.4	24	3,500
0.5	30	3,140
1.0	60	2,216
2.0	120	1,560
3.0	180	1,280

b. Touch Potentials

Touch or hand-to-both-feet contact is shown in Figure IX-3. Here, the potential difference shunted by the body is limited to the maximum value between the touched object and a point approximately one meter (one arm's length) away. This assumes that the touched object is connected to the ground grid immediately below it (this is recommended wherever possible). The parameters in Figure IX-3 are defined below and followed by the development of an equation for calculating tolerable touch potentials:

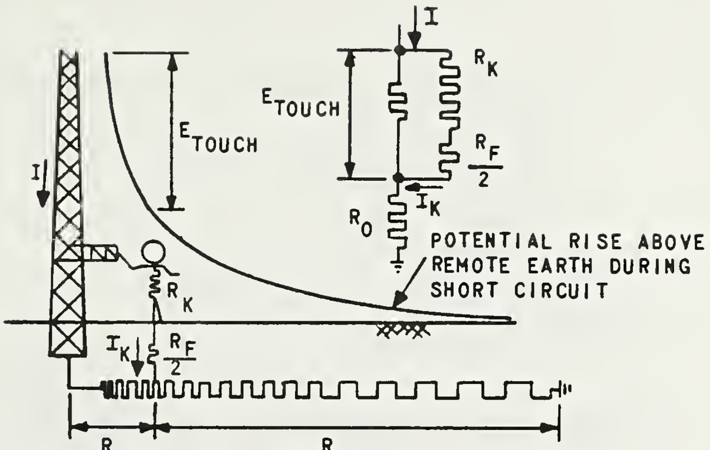


FIGURE IX-3 TOUCH POTENTIALS NEAR GROUNDED STRUCTURE

Parameters of Figure IX-3:

$(R_1 + R_0)$ equals the resistance, in ohms, of the grounding system from the touched object to remote ground.

R_0, R_F, R_k, I, I_k and ρs are defined under C2a. Step Potentials, except in this case the two feet are considered in parallel to the flow of I_k.

E_{touch} is the allowable potential.

Equation for E_{touch}:

$$E_{touch} = (R_k + \frac{R_F}{2}) \quad I_k \qquad \text{IX-11}$$

$$E_{touch} = (1000 + 1.5 \rho_s) \frac{0.116}{t^{1/2}} \qquad \text{IX-12}$$

$$E_{touch} = \frac{116 + 0.17\ \rho_s}{t^{1/2}} \qquad \text{IX-13}$$

For ρ_s = 3000 ohm-meters (for crushed rock)

$$E_{touch} = \frac{116 + 0.17 \times 3000}{t^{1/2}} \qquad \text{IX-14}$$

$$E_{touch} = \frac{626}{t^{1/2}} \qquad \text{IX-15}$$

For a given duration of shock current, in seconds, the allowable E_{touch} determined from the above formula is shown in Table IX-3.

TABLE IX-3

Allowable E_{touch} for Given Duration of Shock Current

Shock Duration, t Seconds	Cycles	E_{touch}, Volts
0.1	6	1,980
0.2	12	1,400
0.3	18	1,140
0.4	24	990
0.5	30	890
1.0	60	626
2.0	120	443
3.0	180	362

c. Transferred Potentials

Transferred potential contact (which may be considered a special case of the "touch" contact) is shown in Figure IX-4. A person standing within the substation touches a conductor grounded at a remote point, or a person standing at a remote point touches a conductor connected to the substation grounding system. Here, the shock voltage may be essentially equal to the full voltage rise of the grounding system under fault conditions and not the fraction of this total which is encountered in the usual "step" or "touch" contacts.

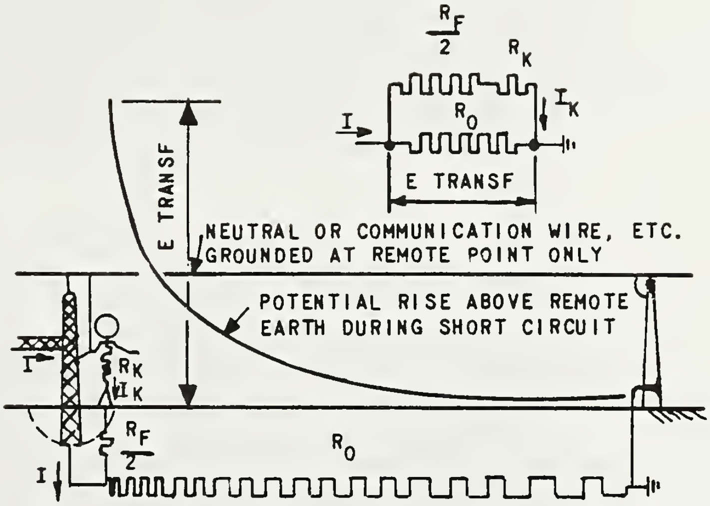


FIGURE IX-4 EXAMPLE OF HAZARD FROM TRANSFERRED POTENTIAL

Parameters of Figure IX-4:

R_0, R_F, R_k, I and I_k are as defined previously.

$E_{transferred}$ = I R_0 considering that the amount I_k is negligible compared to I since $R_{\frac{F}{2}} + R_k$ is many times higher than R_0. IX-16

R_0 can be approximated from the relationship:

$$R_0 = \frac{\rho}{4r} + \frac{\rho}{L} \qquad \text{IX-17}$$

ρ, r and L are as previously defined.

For a given duration of shock current, in seconds, the allowable $E_{transferred}$ is the same as for E_{touch}

d. Total Substation Voltage Rise

In all of the above described situations, for step, touch and transferred potentials, the actual voltage potential encountered by the person involved is related to the total potential rise of the grounding system above remote earth. This fact stresses the importance of keeping that value as low as possible. The total substation voltage rise, E, is equal to IR, where:

E is the total voltage, in volts, rise across the substation grounding system.

I is the portion of the fault current, in amperes, flowing through the grounding system (to or from) remote ground. I is determined from system studies and depends to some extent on the substation grounding resistance, R, as well as on all other impedances and current paths encountered by the fault current.

R is the net resistance, in ohms, of the substation grounding system with respect to remote ground. R depends on the arrangement and extent of the grounding system and on ρ, the earth resistivity, encountered close to the grounding system. R is essentially the only value that can be controlled to some practical extent by the substation designer. Approximately:

$$R = \frac{\rho}{4r} + \frac{\rho}{L} \text{ the same as for } R_0 \text{ under } E_{transferred}. \qquad \text{IX-18}$$

This equation shows that the larger the area covered by the grounding system and the greater the total length of the grounding conductor used, the lower will be the value of R for a given average earth resistivity. The equation also shows that a low earth resistivity is very important in keeping R low.

Earth resistivity varies with the temperature and moisture content of the soil and whether the soil is frozen or unfrozen. For a given location, the earth resistivity is usually not controlled by the substation designer, although in cases of very high soil resistivity, special treatments are sometimes used to help lower the value of ρ.

Whenever the product IR results in a voltage tolerable to the human body according to the allowable values determined previously in Paragraphs C2a., b. & c., there is no danger of ventricular fibrillation to most humans from body contact in any of the cases discussed. If the product IR is in excess of allowable voltage values, then attention must be given to elimination of possible exposure to transferred potentials and further investigation of touch and step potentials.

e. Mesh Voltage

"Mesh" voltage (a form of touch voltage) is taken as being from a grounded structure to the center of a rectangle of the substation grounding grid mesh. Pictorially, this is similar to the situation in Figure IX-3 except that the projection from the grounded structure is greater resulting in a larger R, and consequently a larger value of touch voltage. Mesh voltages represent the highest possible touch voltages that may be encountered within a substation's grounding system and thus represent a practical basis for designing a safe grounding system.

Step voltages within a grid system designed for safe mesh voltages will be well within tolerable limits. This is because step voltages are usually smaller than touch voltages and both feet are in series rather than parallel. Also, the body can tolerate higher currents through a foot-to-foot path since the current does not pass close to the heart.

Transferred voltages are a special matter and, if present at dangerous levels they must be eliminated or avoided.

In a substation that utilizes a grid as part of the grounding systems it is theoretically possible to design and install the grid in such a way that the mesh voltages can be kept within desired limits. For the usual range of grounding conductor sizes, burial depth and spacing, if the fault current flowing into or out of the grounding grid were evenly divided throughout the mesh, and the resistivity of the soil in which the grid is buried were uniform, the mesh

voltage, E_{mesh}, would be equal approximately to ρi, where: ρ is the soil resistivity in ohm-meters and i is the current, in amperes per meter of buried conductor, flowing into the ground.

Practically, however, ρ is not uniform, i is not evenly distributed, and each design is different in some way. Considering this, a more accurate formula for mesh voltage is:

$$E_{mesh} = K_m K_i \rho \frac{I}{L} \quad \text{where:} \qquad \text{IX-19}$$

K_m is a coefficient accounting for number, n; spacing, D; diameter, d; and depth of burial, h, of the grid conductors.

$$K_m = \frac{1}{2\pi} \ln \frac{D^2}{16hd} + \frac{1}{\pi} \ln (3/4)(5/6)(7/8)\ldots\text{etc.} \qquad \text{IX-20}$$

The number of factors in parenthesis is two less than the number of parallel grid conductors, excluding cross connections. For example, in a square grid with eight parallel main conductors and four parallel cross conductors, the number of conductors, n, is eight and the number of factors in Equation IX-20 would be six. The number of cross conductors is ignored.

K_i is an irregularity factor for non-uniformity of ground current flow.

ρ is average resistivity in ohm-meters.

I is maximum total rms current, in amperes, adjusted for ac and dc offset, decrement and future system growth.

L is total length of buried conductor, in meters.

Equating E_{mesh} to maximum tolerable touch voltage and solving for L gives:

$$\frac{K_m K_i \rho I}{L} = \frac{116 + 0.17 \rho_s}{t^{1/2}} \qquad \text{IX-21}$$

$$L = \frac{K_m K_i \rho I \quad t^{1/2}}{116 + 0.17 \rho_s} \qquad \text{IX-22}$$

K_i will vary from about 1.2 to 2 or even more. Examining some square meshes with the same total area but with different numbers of dividing conductors gives a good idea of how the unit current varies with geometry throughout the mesh and in turn its effect on the mesh voltages. Assuming uniform resistivity, Table IX-4 shows the variation in E_{mesh} as an approximate percentage of total IR drop of the grounding system for different grids.

TABLE IX-4
Effect of Mesh Spacing On Mesh Voltages

Square Grid Divided Into Equal Areas	E_{mesh} as percent of IR	
Number of Areas	At Center	At Corners
1	64	-
4	-	45
16	20	30
64	11	20

In such a grid the higher E_{mesh} at the corners can be reduced to approximately the value of E_{mesh} at the center by subdividing each corner into four equal areas. This could be an economical procedure as compared to the alternative of increasing L sufficiently in order to decrease E_{mesh} at the corners to a similar value.

f. Periphery Voltages

Within the grid, step and touch voltages can be decreased to any desired value by decreasing the mesh interval of the grid. Outside the grid, the situation is different and both touch and step potentials require special attention.

(1) Periphery Touch Potentials

Where the fence is tied into the main substation ground grid, the fence becomes the main area of concern for periphery touch potentials. Fence corners and open gates constitute the most dangerous areas because these are locations of greater current densities. The current densities may be 1.5 to 2.0 (or even more) times the densities found at midpoints and the potentials are directly related to the current densities.

These outside touch potentials can be considerably reduced by extending the grid outside the fence a distance of about one meter, so that a person standing outside and touching the fence will be exposed only between points that are close in potential. Also, where dependence is placed on the insulating value of high resistivity surface crushed rock, this material should be extended an adequate distance outside the fence.

(2) Periphery Step Potentials

Extending the grid outside the fence, while helping to reduce outside touch potentials, tends to increase the danger from outside step potentials. The following equation provides a basis for evaluating these step potentials, E_{step}, in a manner similar to that for inside mesh potentials, E_{mesh}.

$$E_{step} = K_s K_i \rho \frac{I}{L} \quad \text{where:} \qquad \text{IX-23}$$

K_i, ρ, I and L are as previously defined for E_{mesh}, Paragraph C2e., and K_s is a coefficient which takes into account the effect of the number, n; the spacing, D; and the depth of burial, h, of the grid conductors. Its value is as follows:

$$K_s = \frac{1}{\pi} \left(\frac{1}{2h} + \frac{1}{D+h} + \frac{1}{2D} + \frac{1}{3D} \ldots \text{etc.}\right) \qquad \text{IX-24}$$

The total number of terms within the brackets is equal to the number of the parallel conductors in the basic grid, excluding cross connections.

K_i can be taken as around 1.5 to 2.0 to account for the higher current densities near the corners and for any projections from the grid. This value assumes uniform soil resistivity and should be increased to cover irregularities in soil resistivity.

Since step potentials are inherently less dangerous than touch potentials, extreme precision is not required. If potentials inside the fence are within safe limits and soil resistivities comparable inside and outside, periphery step potentials are not likely to be a problem. Again, however, if high resistivity crushed rock is greatly relied upon inside the fence, then outside step potentials may be a problem without it.

g. Special Danger Points

(1) Operating Handles

Equipment operating handles are a special circumstance because of the higher probability for coincidence of adverse factors, namely, the presence of a person contacting grounded equipment and performing an operation that can lead to electrical breakdown.

If the grounding system is designed conservatively for safe mesh potentials, then the operator should not be exposed to unsafe voltages. However, due to the uncertainty inherent in substation grounding design, a metal grounding plate or mat, connected to the operating handle and to the grid in at least two places, should be placed where the operator must stand on it to operate the device. This arrangement should be made regardless of whether the operating handle is insulated. See Figure IX-5 for details.

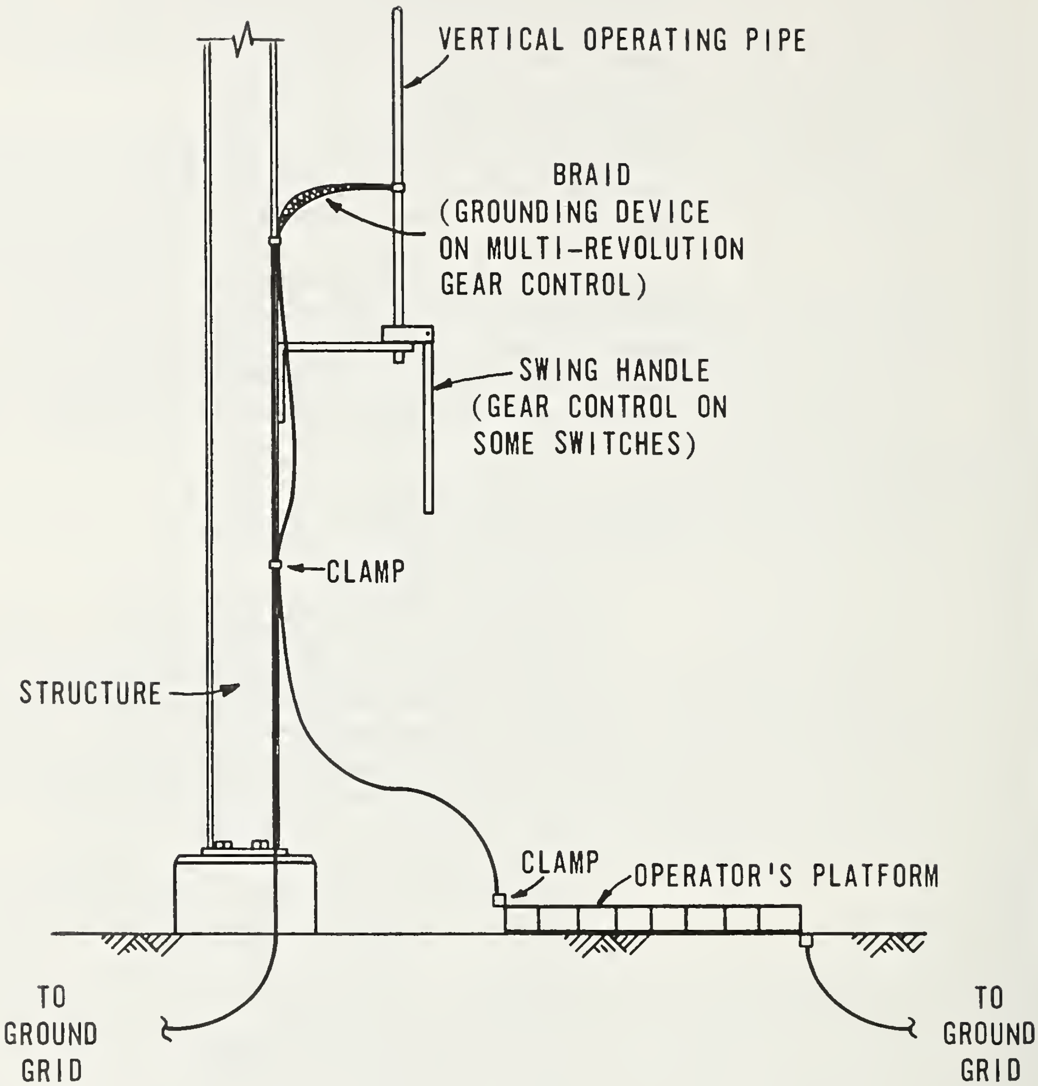


FIGURE IX - 5 TYPICAL SWITCH GROUNDING

(2) Fences

The substation fence should be grounded by means of a loop of conductor buried outside the fence as shown in Figure IX-6. Bonding to the fence, posts and gates should be as detailed in Figure IX-6. The fence ground must be connected to the main substation ground at frequent intervals.

(3) Metallic Cable Sheaths

Metallic cable sheaths must be effectively grounded to prevent dangerous voltages resulting from insulation failure, electrostatic and electromagnetic induction, flow of fault current in the sheath and voltage rise during fault current flow in the substation ground system to which the sheaths are connected. Cable sheaths should be grounded at two or more locations, at cable terminations and at splices and taps. Where the cable sheath may be exposed to excessive ground current flow, a parallel ground cable should be run and connected to both ends.

(4) Surge Arrester Grounding

Surge arresters are designed to pass surge energy from lightning and switching transients to ground, and so are frequently subjected to abnormal current flow to ground. They must be reliably grounded to ensure protection of the equipment they are protecting and to minimize high potential gradients during operation.

The surge arrester grounds should be connected as close as possible to the ground terminals of the apparatus to be protected and have as short and direct a path to earth as practical. Arrester leads should be as free from sharp bends as practical. The tanks of transformers and steel or aluminum structures may be considered as the path for grounding arresters, provided effective connections can be made and

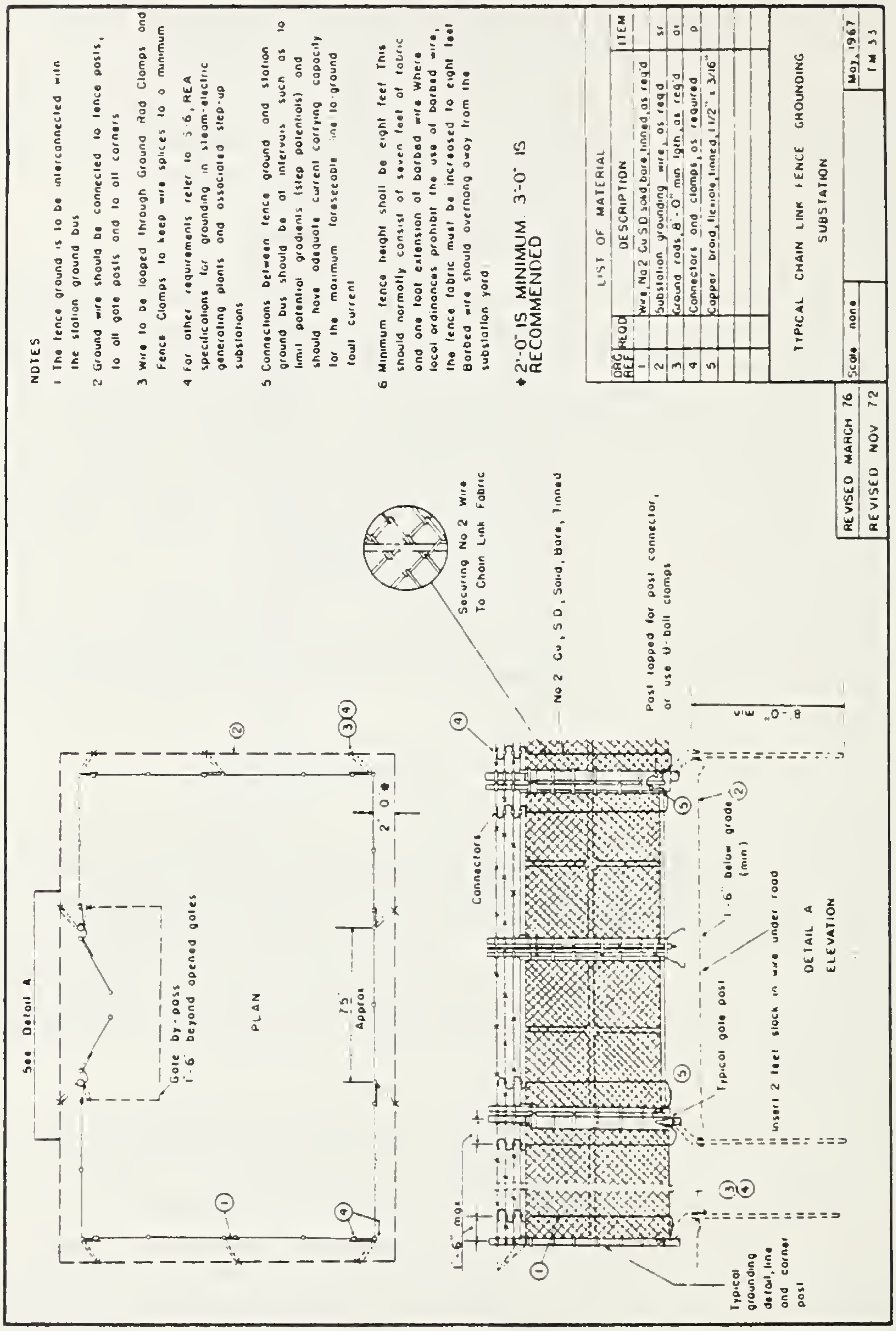


FIGURE IX-6 TYPICAL CHAIN LINK FENCE GROUNDING

secure multiple paths are available. Where there can be any question regarding the adequacy of these paths, it is recommended that a separate copper conductor(s) be used between the arrester ground terminal and the substation grounding grid.

D. <u>DESIGN & INSTALLATION OF A SUBSTATION GROUNDING SYSTEM</u>

1. <u>General</u>

The grounding system shall be designed and installed in accordance with the general philosophy and principles described in IEEE Standard 80, except as modified in this chapter. Although the specific design of an ac outdoor substation grounding system will be described, each user should become familiar with the basic principles in order to adjust or supplement the recommendations, where necessary, to fit the requirements of each substation.

2. <u>Preliminary Data</u>

The following information and data are required for design of a substation grounding system:

a. Layout of fence, structures and equipment to be grounded.

b. Resistivity of soil in area in which ground grid is to be installed. This should be determined by field measurement preferably after it has been brought to rough grade, and before any pipes or cables have been buried. Measurement should be made by the four point method (see Reference 3.). Several locations in the substation area should be checked and at several depths.

c. Maximum phase-to-ground symmetrical rms fault currents computed for ground faults on the substation buses.

d. Maximum grid-to-earth symmetrical rms fault current. This should be determined by taking into consideration the complete system grounding arrangement including connected overhead shield wires, connected grounded neutrals of distribution circuits, and all contributing ground current sources. If this cannot be reasonably determined, a conservative approach is to assume that the maximum phase-to-ground fault current flows from grid-to-earth.

3. Grounding System Arrangement

a. The ground system grid shall consist of a network of bare conductors buried in the earth to provide for grounding connections to grounded neutrals, equipment ground terminals, equipment housings and structures and to limit the maximum possible shock current during ground fault conditions to safe values.

b. The ground grid encompasses all of the area within the substation fence and extends at least 0.61 meters (2.0 feet) (0.91 meters (3.0 feet) is recommended) outside the substation fence. A perimeter grid conductor should be placed 0.61 meters (2.0 feet) minimum (0.91 meters (3.0 feet) is recommended) outside and around the entire substation fence including the gates in any position. A perimeter grid conductor should also surround the substation equipment and structure cluster in cases where the fence is located far from the cluster.

c. The entire area inside the fence and including a minimum of 1.0 meters (3.3 feet) (1.5 meters (4.9 feet) is recommended) outside the fence shall be covered with a minimum of 10 cm (4 in.) layer of crushed rock (or approved equal) possessing a minimum resistivity of 3,000 ohm-meters wet or dry.

d. The ground grid normally consists of main conductors spaced at approximately equal intervals in one direction and secondary conductors running perpendicular to the main conductors and spaced approximately twice the interval between the main conductors. Spacing of the main conductors should not be less than 2 meters (6.6 feet) nor more than 9 meters (29.5 feet). Use should be made of the natural spacing of structures and equipment, where possible, in determining the conductor spacings. In congested areas reduced intervals may be desirable to facilitate connections to equipment and structures. It may also be desirable to subdivide the corner meshes into quarter areas to reduce the normally higher mesh voltages at such locations.

Main conductors and secondary conductors should be bonded at points of crossover where a bonding symbol is indicated on the drawings by brazing with phos-copper (or approved equal) or by welding with the

thermoweld process (or approved equal). Connections to equipment and structures shall occur at junctions between the main and secondary conductors, unless the grid conductor is equal to or larger than the connecting lead size.

e. Grid conductors should be buried a minimum of 45 cm (18 in.) below final earth grade (excluding crushed rock covering) and may be plowed-in or placed in trenches. In soils that are normally quite dry near the surface, deeper burial may be required to obtain desired values of grid resistance.

f. <u>Deep Electrodes</u>

It is often necessary to supplement the grid conductors with deeply placed electrodes. This is required where the earth in which the grid conductors are buried is of resistivity too high to economically achieve a satisfactory resistance to remote earth. Such a situation may occur because of the natural character of the earth. High earth resistivity may also be seasonal because of the earth drying out or becoming frozen. A decision on application of electrodes must necessarily be conservative because of the probabilistic nature of the problem. Serious consideration should be given to application of deep electrodes wherever relatively high resistivity in the shallow earth will be experienced.

Rods are the most commonly used electrodes. Other types of electrodes, such as ground wells, are discussed in the references.

The size of the grid conductors should consider a ground fault current duration of 3 seconds, brazed or welded connections in the grid and fault current introduction at a junction of grid conductors or to a grid conductor equal to connecting lead size. Allow for appropriate future increase in fault current (at least 1.5 times the present). On this basis, the following sizes of copper cable are minimum for the fault currents noted:

Copper Conductor Size	Copper Area-cm	Amperes
#3	52,630	10,000
#1	83,690	15,000
#1/0	105,500	20,000
#3/0	167,800	30,000
#4/0	216,600	40,000
300 MCM	300,000	50,000
500 MCM	500,000	Above 50,000

If high ground fault currents result in a conductor size larger than #4/0 copper, the grid may be arranged to provide the larger conductor only in the area in which the higher currents may occur. Conductor sizes larger than required for electrical reasons may be used where the possibility of physical damage is great.

g. Ground rods, 1.6 cm. (5/8 in.) diameter by at least 2.5 meter (8.0 foot) long copper, steel or other approved type from the List of Materials, REA Guide 43-5, where used should be installed with tops 5 cm (12 in.) minimum below grade and bonded to the ground grid connectors. These rods shall, in general, be installed at all points in the grid where large ground currents may be expected, such as surge arrester connections and transformer neutrals.

The number of and length of ground rods required may be determined using the calculations indicated in Reference 42 of IEEE 80. An additional determinant is having enough rods such that their average fault current pickup would not exceed 300 amperes, assuming all ground system current entering the grid through the rods. Good design practice is to space rods not closer than their length.

4. Trial Grid Layout

Layout a trial grid based on the preceding recommendations; determine the total length of buried conductor including ground rods; adjust the length found so that it is at least equal to the length, L, computed from equation IX-22, Paragraph C2e.

If more precise information is not available, the product $K_m K_i$ may be taken as equal to 2, ρ_s at 3,000 ohm-meters and t at 3.0 seconds. Equation IX-22 then simplifies to

$$L = \frac{\rho I}{180} \qquad \text{IX-25}$$

5. <u>Calculation of Resistance of Grounding System</u>

After layout of grid is complete, calculate the total grid-to-earth resistance by use of equation IX-18, Paragraph C2d.

6. <u>Calculation of Maximum Grid Potential Rise</u>

Using the approximate resistance of the grid, R, calculated above, calculate the maximum grid potential rise above remote earth from E = IR, where I is the portion of the fault current, in amperes, flowing through the grid (to or from) remote ground. If E is less than the safe value of E_{touch} determined from equation IX-13 and provided the value of E is verified after construction, no further grid potential investigation is needed. If E is much smaller than required for safe potential gradients, the grid may be overdesigned. If E is in excess of a safe value, investigation of local potential gradients will be required.

7. <u>Calculation of Step Voltages at Periphery</u>

Using equation IX-23 and the procedure in Paragraph C2f(2) calculate the maximum E_{step} for locations outside the fence. The highest values will be near the corners or near any projections from the main grid. This is due to the higher current densities at these locations. The factor K_i can be roughly calculated from the following equation, where n is the number of parallel main grid conductors in one direction, i.e., excluding cross connections.

$$K_i = 0.65 + 0.72\, n \qquad \text{IX-26}$$

If the value found for outside E_{step} is in excess of a safe value (for allowable E_{step}, use equation IX-7, Paragraph C2a with proper value for ρ_s found outside the fence), then consideration should be given to the best means of achieving a reduction.

Inspection of the parameters in equation IX-23 will suggest the options available. The parameters that may possibly be varied are:

n: Number of parallel conductors, excluding cross connections

D: Spacing of parallel conductors

h: Depth of burial of parallel conductors

ρ: resistivity of the soil in which the conductors are buried

L: Total length of buried conductor

I: Effective maximum rms current during shock duration adjusted for future system growth.

8. <u>Calculation of Internal Step and Touch Voltages</u>

If total length of buried conductor is made equal to L calculated from equation IX-22, then step and touch voltages within the grid perimeter should be within tolerable limits.

However, where major irregularities exist in the geometry of the grid or important anomalies are suspected in ground resistivity, more detailed investigation may be necessary.

9. <u>Investigation of Transferred Potentials</u>

A potential hazard may result during a ground fault from the transfer of potentials between the ground grid areas and outside points, by conductors such as communication circuits, low-voltage neutral wires, conduit, pipes, rails, metallic fences, etc. The danger is usually of the touch type, and the potential difference may approach the full value of the ground grid potential rise.

The presence of any situations involving possible transferred potentials should be carefully examined and steps taken to eliminate or avoid them. Paragraph 15 of IEEE 80 discusses many such situations in greater detail.

10. Effect of Sustained Ground Currents

After the grounding design has been established as safe for the maximum ground-fault current at the appropriate clearing time, step and touch voltages should be checked for sustained ground currents.

Sustained currents are those currents below the setting of protective relays and may flow for a long time. Body currents produced as a result of these long duration currents should be below safe let-go values. In most cases, it would be advisable to limit such currents to 5 mA.

11. Connections From Equipment and Structures To Ground Grid

Careful attention must be accorded the connections of substation structures, equipment frames and neutrals to the ground grid to realize the benefits of an effective ground grid system. Conductors must be of adequate size to carry the maximum fault current that could occur, and the connections must be securely made to resist corrosion and mechanical damage. Extra connections should be considered at all critical locations (such as at equipment neutrals, surge arrester grounds, operating handles and ground mats, etc.) to ensure an effective grounding capability even when one conductor is broken or a connection is improperly made. Following are recommendations applicable to grounding connections:

a. Conductor shall be of stranded copper conductor (or approved equal) and sized to carry for 3 seconds duration without fusing the maximum phase-to-ground symmetrical fault current that may be conducted to ground by the particular connection. Equation IX-27 may be used for determining adequate conductor sizes to avoid fusing. Three seconds is chosen as a reasonable time of conduction, since it is used for the short-time rating of switchgear.

$$I=A\left[\frac{\log_{10}\left(\frac{T_m - T_a}{234 + T_a} + 1\right)}{33S}\right]^{\frac{1}{2}} \qquad \text{IX-27}$$

I: Current, in amperes (allow for future increase).

A: Copper cross-section, in circular mils.

S: Time, in seconds, during which current I is applied.

T_m: Maximum allowable temperature, in degrees C.

T_a: Ambient temperature, in degrees C.

The following assumptions may normally be made in applying the above equation:

Ambient temperature of 40 degrees C.

All heat retained in conductor because of short time duration.

Melting point of copper, 1083 degrees C.

Allowable temperature, brazed joints 450 degrees C.

Allowable temperature, bolted joints 250 degrees C.

Appropriate adjustments must be made for materials other than copper.

Conductor sizes for any critical connection should not be smaller than 1/0 AWG to assure mechanical adequacy.

b. Conductor shall be brazed or thermowelded to the grid at a crossover point of grid conductors or to a grid conductor of equal size.

c. The conductor shall be the shortest possible length.

d. The conductor shall be securely attached to structures and/or equipment and formed to conform to foundation with minimum exposure to mechanical damage.

e. In the portion below earth, the conductor shall be covered to a depth of at least 15 cm (6 inches).

f. The conductor shall be connected to equipment and/or structures with clamp-type connectors or by bolted lugs welded or brazed to the conductor.

   Paint, enamel and corrosion shall be removed from points of contact before connections are made.

E. Measuring Earth Resistance and Resistivity For Electrical Grounding Systems

Reliable earth resistivity measurements of the soil in which the grounding system grid and rods will be installed are essential for the proper design of a grounding system. After the grounding system has been installed, it is important that accurate measurements be made periodically of the overall substation grounding system resistance with respect to remote earth.

A good reference useful for an understanding of both resistivity and grounding system resistance measurements is contained in the manual entitled "Getting Down-To-Earth" by the James G. Biddle Co. Helpful information is given in IEEE Guide-80 as well as in some of the other references in the Bibliography.

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CHAPTER X - INSULATED CABLES & RACEWAYS

A. GENERAL

This chapter covers the application and selection of low voltage, high voltage, and special cables, and raceways for cable protection. Low voltage cables are defined as those operating at 600 volts and below, high voltage as those operating above 600 volts, and special cables as those operating in the radio frequency spectrum, i.e. 30 kHz and above.

The borrower is referred to the following IEEE publications for additional data on substation cables:

P525 - Guide for Selection and Installation of Control and Low-Voltage Cable Systems in Substations
P422 - Guide for Design and Installation of Wire & Cable Systems in Power Generating Stations.

Raceways are discussed, starting with Section E.

B. 600 VOLT CABLE

1. Circuit Requirements

600 volt circuits can be divided into two main categories, power circuits and control circuits. Substation power circuits are those supplying cooling fans, insulating oil pumps, air compressors, apparatus heaters, luminaires and similar three phase and single phase loads. Voltage levels and connections vary depending on the application. These can be:

a. 480/240 volt, three phase delta connected
b. 480/277 volt, three phase wye connected
c. 208/120 volt, three phase wye connected
d. 240 volt, three phase delta connected
e. 240/120 volt, three phase closed or open delta connected with one phase center tapped
f. 240/120 volt, single phase three wire

The relative merits of these six alternatives are covered in detail and illustrated in Chapter XIV, AC and DC Auxiliary Systems.

Substation control circuits are those which execute a command to and/or indicate the status of a piece of apparatus such as a circuit breaker. Control circuits also include those concerned with currents and voltages for relaying and similar purposes. These circuits usually operate at less than 300 volts and may be dc or ac. Typical examples are current and potential circuits for protective relays and metering devices and trip or close commands to automatic protective devices. Communication, supervisory control, and data acquisition systems (SCADAS) circuitry fall under the category of control circuits.

In spite of the usually lower voltage level of control circuitry, a minimum insulation level of 600 volts should be specified. 600 volt cable is more readily available than 300 volt cable and the slight, if any, price difference is generally not an equitable trade for the additional protection provided by the 600 volt insulation. An exception to the above rule may be a requirement of several thousand feet of low voltage, (48 volt) circuitry. In this instance 300 volt insulation should be considered as a possible economic advantage.

2. Conductors

600 volt insulated power and control circuit conductors may be copper or aluminum, solid or stranded. Because of the lower termination reliability of aluminum, and lower ampacity, copper is generally preferred.

Power circuit conductors should be No. 12 AWG minimum size. Stranded conductors are easier to handle and lend themselves to compression or bolted lugs and connectors.

Control circuit conductors, because of low ampacity requirements, are often smaller than No. 12 AWG. Stranding can be such to permit flexibility. A typical No. 12 AWG control conductor could be made up of 19 strands of No. 25 AWG copper whereas a power conductor would be made up of seven strands of No. 19 AWG.

Stranding of individual conductors is basically concentric and rope stranding. Concentric cable stranding is defined as a cable consisting of a central wire surrounded by one or more helically laid wires with the lay direction the same for all layers. A rope stranded cable consists of groups of concentric cables. Concentric cable has a more nearly circular cross section permitting the best centering

of the conductor within the insulation. General use 600 volt cable is manufactured concentric strand. Rope stranded power cable is available as flexible and extra flexible and the cost is such as to preclude use for 600 volt circuits. An exception would be the use of very short lengths of a large diameter cable, the flexibility making termination easier, or where excessive conductor movement is inevitable. Such situations should be avoided, if possible.

3. Conductor Configurations

Insulated conductors are manufactured as single or multi-conductor cables, shielded or nonshielded, and for power conductors with or without armor.

Control circuit conductors are usually specified as multiconductor cables. This has the basic advantage of one specific multi-conductor circuit laying in one place instead of several places. This could be the case with a four conductor current transformer circuit.

a. Color Coding

Control circuit multi-conductor cables can be purchased with all wires colored black or the wires color coded. Color coding should be by the Insulated Power Cable Engineers Association (IPCEA) methods.

Colored insulation compounds with tracers is the most widely used method, identification being simple (IPCEA method No. 1). The color coding methods are specified in IPCEA Publications No. S-61-402 and S-19-81.

Color coding for substation control circuits, even single conductor circuits, is recommended. Standard codes can be established for circuit functions and individual wire functions. For example, a green wire standardized as a "trip" wire and a red wire standardized as a "close" wire for power circuit breaker control duplicates the color practice for pilot lights on control panels indicating breaker status. In addition, color coding can assist greatly in "ringing-out" control circuits, especially in large substations. It is recommended that for additions to a non-coded substation, a color coding scheme be established for the addition.

All black control wires may be used for a strictly temporary control installation of minor size at the option of the Engineer.

Telephone and telemetering circuits where used should utilize the 25 pair count color code method, IPCEA Publication S-56-434, REA Specifications PE-22, PE-23, PE-28, PD-38 and PE-50. Except for lighting circuits, power conductor color coding need not be used. Circuits can be tagged for phase indication and wire number after "ringing-out". Lighting circuit conductors are specified single conductor with the neutral being a white color and a feed or switch wire black. It is recommended that three-way switch dummy wires be coded red and blue, reserving green for a bonding conductor, where required.

b. Shielding

Conductor shielding of control circuit cables is specified basically to prevent a false signal from being inductively coupled to a control circuit from an energized high voltage bus or from the switching operation of high voltage disconnecting equipment. As a general rule, a 230 kV substation with electromechanical protective relays, need not include shielded control cables. However, if solid state relays or supervisory remote terminal units are planned, a study with reference to control cable shielding should be made.

Conductor shielding, where required for control circuit conductors, consists of a metallic covering completely enclosing the conductor bundle. Individual conductor shielding is available but is not applicable at 230 kV and below. Where shields are used, they should be grounded as outlined in Chapter IX - Grounding.

4. Conductor Insulation and Jackets

A very important parameter in wire or cable selection is the insulation. Insulation selection should be based on the properties of life, dielectric characteristics, resistance to flame, mechanical strength and flexibility, temperature capability and moisture resistance. Insulation types applicable to substation conductors are:

Ethylene Propylene Rubber	EPR
Polyvinyl Chloride	PVC
Polyethylene	PE
Irradiated Polyvinyl Chloride	PVC (I)
Chemically Cross-Linked Polyethylene	XLPE
Irradiated Cross-Linked Polyethylene	XLPE (I)
Flame Retardant Polyethylene	FRPE

The Oxygen Index (O.I.) of a plastic insulated wire or cable is a measure of the fire propogation resistance of the material as determined by the Fire Test of IEEE Standard 422. Air normally contains 21 percent oxygen; hence a material with oxygen index below 21 will burn readily in air. A cable O.I. of 27 or greater is generally high enough to pass the IEEE Fire Test.

Table X-I lists the basic properties of the insulating materials under consideration.

TABLE X-I
Properties of Cable Insulating Materials

Material	Max. Oper. Temp. °C (°F)	Oxygen Index	Cost (Low-Moderate-High)
EPR	90 (194)	20	M
PVC	75 (167)	26-30	L
PE	75 (167)	18	L
PVC (I)	75 (167)	27	M
XLPE	90 (194)	18	M
XLPE (I)	90 (194)	18	M
FRPE	75 (167)	27	M

Minimum acceptable insulation thickness shall be as specified by the Insulated Power Cable Engineers Society (IPCEA). As an example, a current circuit cable may be specified as: 4/c No. 9 AWG, 19 strand, 30 mils P.E. insulation each conductor, 15 mils PVC covering each conductor, 60 mils PVC overall jacket.

Since no one insulating material fulfills all requirements, engineering judgment is required for selection of insulation for 600 volt substation wiring. Economic judgment must also be exercised as to standardization.

The National Electrical Code (NEC) contains tables showing temperature ratings and location restraints of insulation. The design Engineer should also use the wealth of information available to him from cable manufacturers' data.

Jackets are used over individual insulated wires or over multi-conductor cables to provide protection against mechanical damage, sunlight exposure, moisture, oil, acids, alkalies, and flame. Some insulating materials used on single conductor circuits, notably lighting circuits, have the required protection without the use of additional jackets. An example is N.E.C. Type TW which is a 60°C, flame retardant, moisture resistant thermoplastic insulation suitable for conduit, tray or trench installation.

Jacket materials currently in use on 600 volt cables are neoprene, O.I. 27-30, and polyvinyl chloride. Both of these materials are moisture, acid, and alkali resistant and flame retardant.

Neoprene is also oil resistant. PVC is less costly compared to neoprene but it is also less flexible. Other jacket materials are also commercially available.

5. Cable Sizing

In substation design, the important element of cable sizing is current carrying capacity. Voltage drop is a secondary factor except with current transformer circuits, tripping circuits and in very large installations where conductor distances are long. What circuit lengths are to be considered long is a matter of design experience. In lieu of such a background the Engineer should check for voltage drop of the longest circuit, using the conductor size and the current capacity dictated. The voltage loss in a conductor should not be such as to cause faulty operation of the device being fed by the conductors. For power circuits, 3 to 5 percent loss is tolerable with reasonable regulation. Electric motors are rated for satisfactory operation at $\pm$ 10 percent voltage, electric heating elements will operate satisfactorily within the same range. If any doubt exists the Engineer should contact the equipment manufacturer to determine voltage

tolerances applicable. Manufacturers data includes voltage drop tables. Where such data is unavailable, voltage drop should be computed.

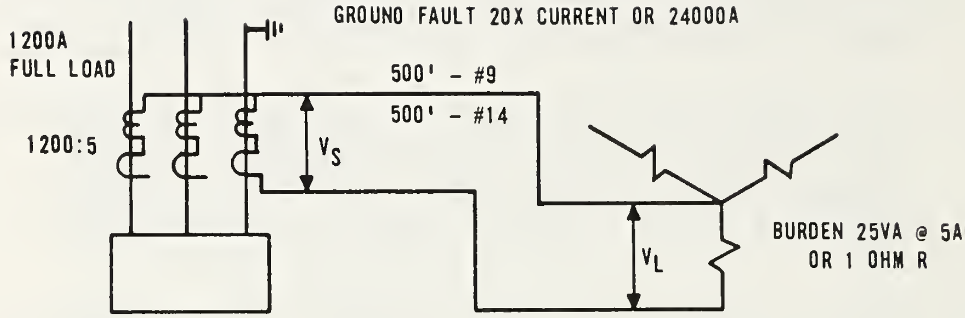
Voltage drop in current transformer circuits should be considered. Refering to Figure X-1, with a 10C400 transformer, No. 14 AWG leads are required. With a 10C200 transformer, No. 9 AWG leads are proper. In other words current transformer circuit voltage drop should be computed to select cable size to keep the current transformer ratio error within acceptable limits. Given a certain current transformer class furnished with equipment, the leads must be sized for the given current transformer. A 10C200 current transformer can maintain 200 volts across the secondary terminals and hold the ratio error within 10 percent when 20 times full load current is applied.

Conductor selection based on current carrying capacity is made by computing the current required to serve the load. The wire or cable is selected from applicable Articles of the N.E.C. or from manufacturer's data. This applies to both control and power conductors. The N.E.C. contains examples of branch and feeder circuit size calculations.

The current carrying capacity of a given size conductor is not a constant. The ampacity varies depending on the installation condition. Conductors for use in free air are rated higher than those in conduit. Over three conductors in a conduit also lowers the current carrying capacity of each individual conductor.

In general, conductor insulation short circuit capability for 600 volt substation service need not be considered. As an example, No. 9 AWG copper with XLPE insulation may carry up to 5000 Amperes without conductor failure.

The Borrower should establish standard conductor sizes for his particular system. As an example 4/c No. 9 for current transformer circuits, 5/c No. 12 for potential circuits, 8/c or 10/c No. 12 for multipurpose control and 1/c No. 12 for miscellaneous relay interconnections and so forth, can be used. Standardization can result in cost savings by quantity purchases and, if standard sizes are stocked, long leadtime for maintenance work can be eliminated.



I_F = 100A
R = 0.79 OHMS/1000' - #9
R = 2.5 OHMS/1000' - #14

IR DROP	#9	100 x 0.79	= 79V
	#14	100 x 2.5	= 250V
V_L		100 x 1.0	= 100V

V_S	#9	179V
V_S	#14	350V

<u>FIGURE X-1</u>

<u>VOLTAGE DROP FOR CURRENT TRANSFORMER CIRCUITS</u>

6. Segregation of Control Cables

Low voltage circuits providing instrumentation and control functions in a substation are subject to failures and damage. The installation of these circuits to minimize damage, upon failure, to adjacent circuits is one of the prime concerns in substation design. The Borrower should decide, based on operating history, the substation voltage level where such damage may result in reduced reliability.

A method of approaching a solution to the possible damage situation is by circuit isolation or segregation. Approaching a solution is stated here because materials, methods and costs dictate design practices which may fall short of providing perfect isolation. The best design is a balance of reliability and cost.

To prevent damage to adjacent cables, the following guide lines should be applied at least in 230 kV and higher voltage substations. Operating history may dictate use at 115 kV or lower voltage substations.

The suggested guide lines are:

(a) Isolate circuits having greatest exposure to primary voltage such as potential and current transformer secondaries
(b) Group wiring from one power circuit breaker position and isolate from other breaker positions
(c) Group wiring from one bus differential
(d) Group wiring from one transformer differential
(e) Route ac circuits on one side of a relay or control panel and dc circuits on the other side
(f) Group metering, alarm, and low voltage (120 volt) control house circuits
(g) Divide trays with grounded metal barriers

Segregation of control cables also simplifies original circuit testing, maintenance procedures, substation additions and constitutes "good housekeeping".

From these suggested guide lines and from operating history, the Borrower can establish control cable segregation standards for his system. All substations on a system should be the same, promoting ease of testing and maintenance and possibly an increase in reliability.

7. <u>Installation Considerations</u>

Cable failures occurring during precommission testing and/or shortly after substation service has began can often be traced to insulation failure caused by construction abuse or design inadequacy. Insulation can be damaged by excessive pulling tension during construction. Conduit elbows selected with too little radius could result in insulation flattening during installation.

Bending radius for general use power and control cables is dependent on insulation type, number of conductors, size of conductors, and shielding. The Borrower should establish standards for his system based on cable manufacturers' recommendations.

Cable damage can also occur through the entry of moisture at an unsealed end. When a cut is made from a reel, the reel end should be sealed against moisture. Cable ends, prior to connections, should be sealed. Lugs for use in moist locations should be shrouded type.

Construction specifications should state that unlagged reels are not to be handled by lift trucks. Cable is to be properly stored at all times to prevent damage. Common sense handling by concerned personnel can prevent cable damage both in storage and in the field.

Construction specifications should also require that:

a. Wherever possible, cables shall be run from outdoor equipment to the control house without splices
b. Control cable splices shall be made indoors at least five feet above the floor
c. Taps and splices in trays shall not be buried under other cables
d. Splices shall never be buried in earth or pulled in conduits or ducts
e. Wires, splices and taps in metal junction boxes shall never be under cover pressure. An adequately sized box should be specified.
f. Specifications and layouts should be designed to avoid sharp corners and also to provide adequate space for pulling cables into place with a minimum of rigging.

Where relatively large conductors, #1/0 and above, are used in three phase circuits and the quantity justifies it, consideration should be given to ordering three or four conductors on a single reel. Such a consideration is an obvious installation labor saving decision.

It is advisable, when a length is cut from a reel, that the new reel length be recorded. Inventory is possible when this is done and a project has less chance of delay because of lack of material control.

Cable terminations should allow enough slack to prevent tension on the terminating lugs.

C. HIGH VOLTAGE POWER CABLE

The use of high voltage power cable (over 600 volts) not used for transmission, subtransmission or distribution circuits is generally limited to the primary feed or feeds to the auxiliary system. This cable is covered in Chapter XIV "AC and DC Auxiliary Systems."

D. SPECIALIZED CABLE

Substation cable in this category, consists of coaxial cables for low frequency (30 kHz-300 kHz) use in carrier communications and for ultra high frequency (300 mHz-3 gHz) use in microwave systems.

Coaxial cables for carrier communications are available with surge impedance (Zo) of 50 and 75 ohms, 50 ohms being the most common. Because of the low power requirements of carrier systems, cable power rating need not be considered. The primary consideration is jacket material. Some jackets contain plasticizers, which when exposed to weather, leach into the center insulator seriously increasing power losses and making replacement necessary in approximately five years.

Noncontaminating jackets are available where the life of the jacket is 20 years or more. The cost differential of a few cents per foot is worth the added reliability.

Recommended coaxial cable for carrier communcation use is RG-213/U having a noncontaminating jacket and nominal Zo of 50 ohms.

Coaxial cable for microwave communication (3.0 gHz and below) is a part of a more sophisticated system. Losses and power rating should be taken into consideration.

Microwave coaxial cable, 50 ohms Zo, is available with air dielectric and foam dielectric. Air dielectric cable, to prevent moisture entry, is pressurized with inert gas, usually nitrogen. At a given frequency, cable with air dielectric has less attenuation than with foam dielectric, but the pressure system must be monitored. Foam dielectric is the preferred cable. The transmitter may have to be specified with power to overcome the cable attenuation but this can be minimized with attention to equipment location keeping coaxial leads short. A detailed selection procedure for microwave cable is covered in manufacturers' handbooks.

If spectrum space below 3.0 gHz is unavailable, the Borrower wishing to use microwave communications may have to apply for a higher frequency. Above 3.0 gHz, coaxial cables exhibit far too much attenuation for practical use necessitating use of wave guides. Wave guide application is beyond the scope of this bulletin.

E. RACEWAYS

1. FUNCTION

Raceways, in the form of conduits, trays, and trenches, are used in substations to provide protection and electrical segregation of cables.

Historically, raceway materials evolved as materials evolved, brought on mainly by increasing labor costs. Steel conduit was followed by fiber and cement asbestos conduit. The lower weight and easier tooling was the main advantage. Block trenches, and cast in place concrete trenches followed. These trenches while economically about the same as concrete encased ducts, reduced the potentially damaging cable pulling, cables being layed in the trench. Precast concrete trench, knocked down for field assembly, then became available. Plastic conduit followed and is a stock item with many electrical suppliers. Other materials for raceway use will appear on the scene, as market potential requires.

2. ECONOMICS

The economics of a raceway system for a substation hinges on a cost/benefit ratio. A balance between required reliability and the cost of such reliability should be established.

The design costs of various systems generally will not vary, appreciably. More design will be required for an underground duct system, for a large substation, than would be required for precast trench.

Delivery charges to the site of various materials, site handling costs, and installation labor costs are the major items to be considered for an economic evaluation. Simplicity of expansion, ease of testing, maintenance and cable replacement, personnel safety, security and appearance may, in part or in total, be factors for consideration when alternate systems are being studied.

In addition to items discussed in this guide many trade publications are available and should be used as necessary.

F. UNDERGROUND RACEWAYS

All underground systems offer the same "out of way" appearance and the same degree of security and as such are irrelevant when comparing one system to another.

In this guide, the use of underground metallic conduit for other than 1/2 in. and 3/4 in. lighting circuits will not be considered. The labor and material costs prohibit such an installation.

Underground methods available are:

1. Direct burial cable
2. Direct burial conduit
3. Concrete encased conduit (duct bank)
4. Cable Trenches (partially underground).

1. Direct Buried Cable

Direct buried cable, although the least costly underground method, should generally be avoided except for lighting branch circuits and then in small installations. Circuit reliability can be continually threatened by excavation. Metallic armored cables can minimize this damage and potential personnel hazard, but sacrifice the lower cost.

Most cables, control and power, with insulation suitable for any below grade installation are suitable for direct burial. However, without a surrounding case (conduit) the cables are subject to damage by burrowing animals.

Concentric neutral cables can be subject to corrosion and destruction of the neutral. Several factors can cause this corrosion, hence the advantage of this type of cable can be lost. The engineer is referred to IEEE Catalog No. 77CH1202-11A which contains a paper presented at the 1977 Rural Electric Conference dealing with neutral corrosion and Chapter XI of this guide.

Trenches for direct buried cables are shown in REA Form 806 Jan. 1972, drawings UR2, UR2-1 to UR-5 inclusive.

Advantages

a. Minimum width of excavation
b. Cable can be layed in with no pulling damage
c. Minimum conduit labor and material cost (equipment risers only required)
d. "In-line" handholes or manholes not required

Disadvantages

a. Testing should be done prior to backfilling trench, leaving cable exposed to potential damage
b. "Dig-in" damage possible
c. Trench bottom and backfill material must be carefully inspected. Original excavated material may be unsatisfactory for backfill, requiring purchase and delivery of proper material
d. Electrical circuit segregation, without separate or wide trenches, may not be possible
e. Cable replacement or cable additions require additional excavation
f. Possibility of neutral corrosion

2. Direct Buried Conduit

In a small distribution substation, direct buried nonmetalic conduit for control and power cable including lighting circuits should offer the most economical underground system or cost/benefit ratio.

Non-metallic conduit with a wall thickness suitable for direct earth burial should be selected. Fittings for the conduit, be it plastic, fiber or cement asbestos, should

be procured from the manufactures of the conduit. This will ensure component compatibility.

Except for equipment risers, conduit bends should be avoided to limit cable pulling tension. For cables with neoprene, polyethylene or PVC jackets, pulling tension should be limited to 454 kg (1000 lbs) when pulled with a basket grip. Control cables with conductors No. 16 AWG and smaller should be limited to 40 percent of this value or lower if recommended by the manufacturer.

In the design phase, conductor pulling tension should be calculated using:

$$T = lwf \qquad \text{X-1}$$

Where T: tension, in kilograms (pounds)
l: Length of conduit run, in meters (feet)
w: Unit weight of cable, in kilograms/meter (pounds/foot)
f: coefficient of friction (0.5)*

* f may be decreased by using pulling lubricants.

This relation should be used in the computation and the worst case compared to the maximum allowable tension. Excessive lengths should be reduced with handholes or manholes to provide pulling points.

Equation X-1 is used to determine the pulling tension for a given conduit length. Given the tension, the maximum length (L) can be found from:

$$L = \frac{T}{wf} \qquad \text{X-2}$$

Direct buried conduit banks can be installed in the same way as concrete encased, see Section F.3, less the concrete. The cable derating factors discussed in Section F.3 must be applied.

Advantages

a. "Dig-in" damage reduced
b. Excavation, conduit placement, backfilling can be one operation
c. Electrical circuit segregation possible
d. Burrowing animal damage to cable prevented
e. Ease of expansion
f. Ease of cable replacement

Disadvantages

a. Cables are pulled; hence, care is required to prevent damage
b. Manholes or handholes may be required
c. Backfill material requires inspection as to suitability

3. Concrete Encased Conduit (Duct Bank)

Concrete encased duct bank application is decreasing in popularity giving way to cable trenches. In spite of the growing popularity of cable trench use in substations, cases exist where duct banks must be used, either with or without concrete encasement. Cases in point could include conduits passing under heavy traffic roads, posing a barrier to equipment movement, or blocking natural drainage. The Engineer must resolve this or similar situations when determining the preferred raceway system.

When several cables are placed in the same duct bank the operating temperature of the inner cables could exceed the safe operating temperature of the cable insulation. To prevent this situation, the loads must be multiplied by a position factor. Figure X-2. sites examples of these position factors.

For an underground installation, excavation work should be specified as called for in Chapter VI. The designer should indicate a pitch of 10.2 centimeters per 30.5 meters (4 inches per 100 feet) for duct drainage.

There are two types of duct bank: built up and tier. The built-up method consists of laying conduits on fabricated plastic spacers, sized to the conduit outside diameter and desired separation. Base spacers allow for 7.6 centimeters (3 inches) of concrete below the bottom row of conduits (ducts). Intermediate spacers are placed on the top of the bottom and succeeding layers of ducts to the desired height. Spacers are placed on both sides of couplings, the couplings being staggered along the run. When the entire bank is constructed and inspected to ensure ducts are aligned and continuous, the entire duct bank is enclosed with machine mixed concrete grout, usually a 1:6 mix. The monolithic pour of the built-up method is usually used with very careful supervision of all steps to eliminate the faults prevented by tiering. Figure X-3 illustrates monolithic duct bank construction.

95	95
83	83
83	83
95	95

AVERAGE = 89

100	100
100	100

AVERAGE = 100

91	77	91
75	60	75
75	60	75
91	77	91

AVERAGE = 78

93	79	93
79	64	79
93	79	93

AVERAGE = 83.5

93	93
80	80
78	78
76	76
76	76
78	78
80	80
93	93

AVERAGE = 82

89	71	71	89
71	48	48	71
71	48	48	71
89	71	71	89

AVERAGE = 70

90	77	90
73	55	73
71	52	71
70	47	70
70	47	70
71	52	71
73	55	73
90	77	90

AVERAGE = 70

85	65	62	62	65	85
65	38	31	31	38	65
62	31	20	20	31	62
62	31	20	20	31	62
65	38	31	31	38	65
85	65	62	62	65	85

AVERAGE = 51

RELATIVE WATT LOSSES FOR INDIVIDUAL DUCTS AND BANK OF DUCTS PER FOOT OF CABLE FOR SAME TEMPERATURE RISE (PERCENT OF 2 BY 2 BANK)

$$\text{POSITION FACTOR} = \sqrt{\frac{\text{RELATIVE LOSS FOR ANY DUCT}}{\text{AVERAGE LOSS}}}$$

FIGURE X-2 DUCT BANK POSITION FACTORS

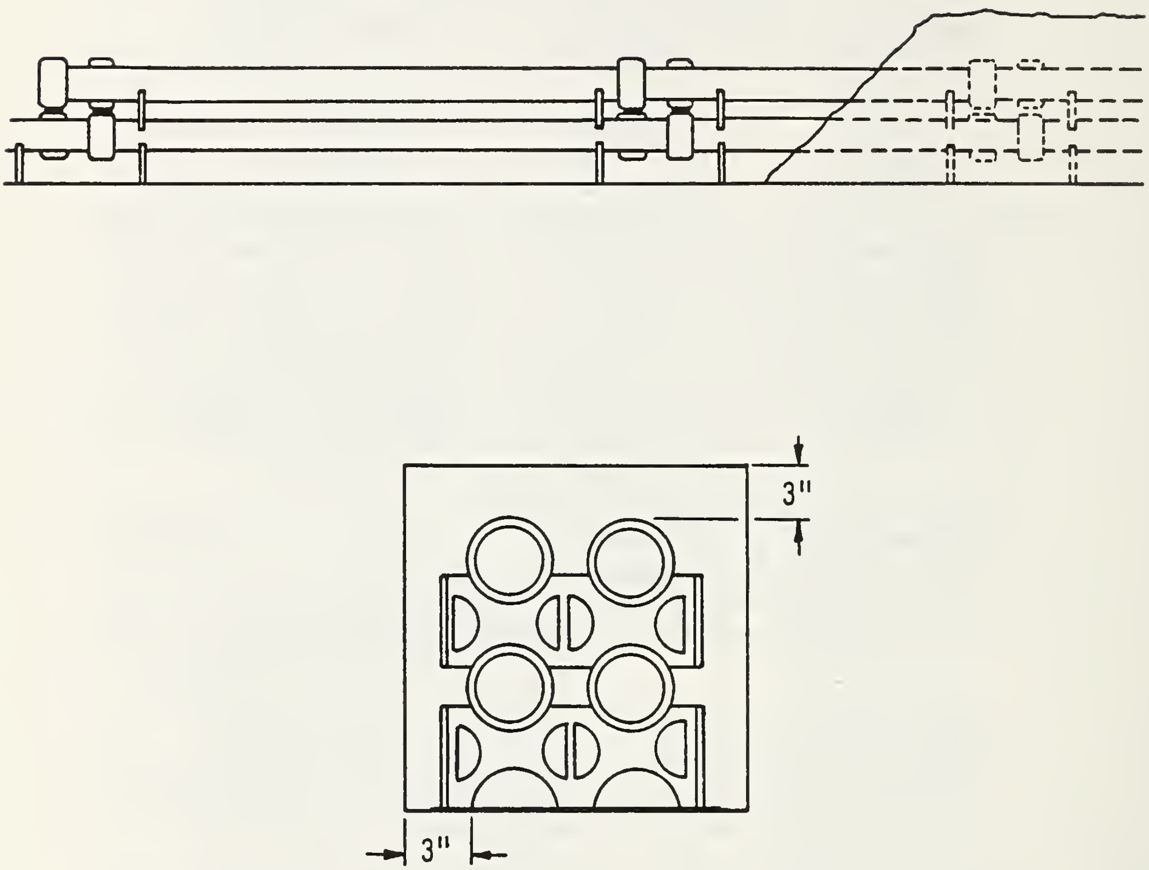


FIGURE X-3

MONOLOTHIC DUCT BANK CONSTRUCTION

The tier method consists of placing a 3 in. layer of concrete in the bottom of the trench. After an initial set, the bottom row of ducts is layed with separation maintained by wooden or metal combs with the cross bar thickness equal to the required vertical separation. Concrete is poured, screeded to the comb tops. After partial set, the combs are removed and the process repeated to the full height of the duct bank. Figure X-4 lists the amount of concrete required for various duct combinations. The tier method is obviously more costly but concrete voids, duct separation and duct floating are prevented.

<u>Advantages</u>

a. Permanent
b. Accidental cable damage by "dig-in" improbable
c. Ease of cable replacement
d. Electrical circuit segregation possible
e. Burrowing animal damage impossible

<u>Disadvantages</u>

a. Cost
b. Substation expansion must be considered
c. Derating of certain cables required in large duct banks

4. <u>Cable Trenches</u>

The most significant advantage of cable trench use is the saving of labor during cable installation plus the absence of cable pulling damage. Trenches are becoming the most acceptable cable installation method, particularly in large installations.

Cable trenches may be constructed in several ways.

a. <u>Block Construction</u>

If block construction is planned for a control house, economy may indicate block trench. Core or solid, concrete or cinder block is satisfactory for cable trench. Covers can be fabricated from checkered plate aluminum or light weight concrete. Figure X-5 illustrates suggested construction.

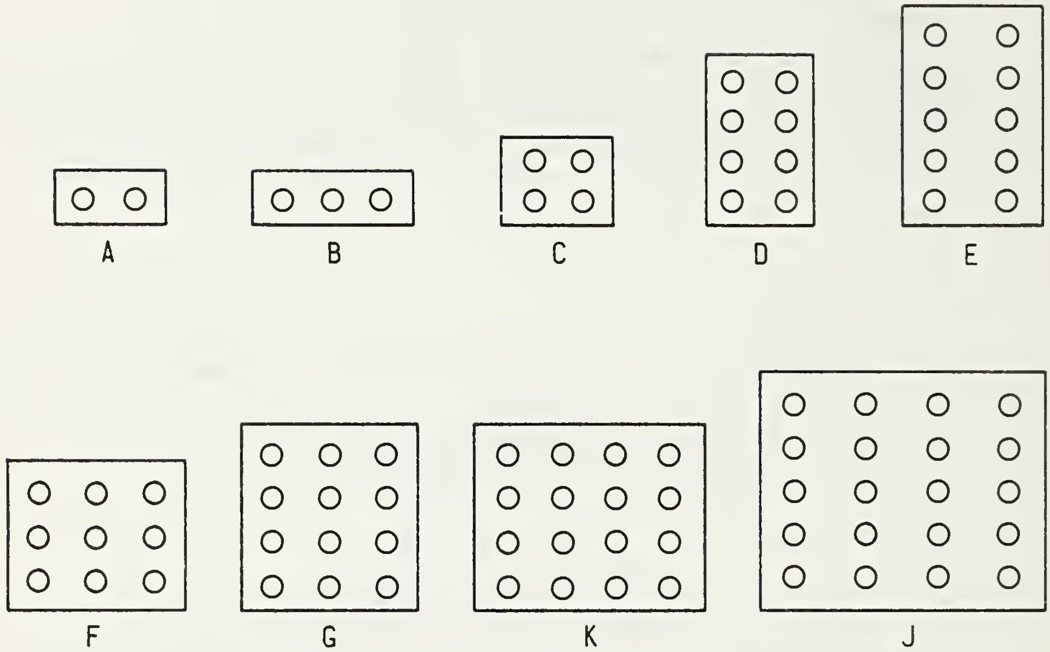
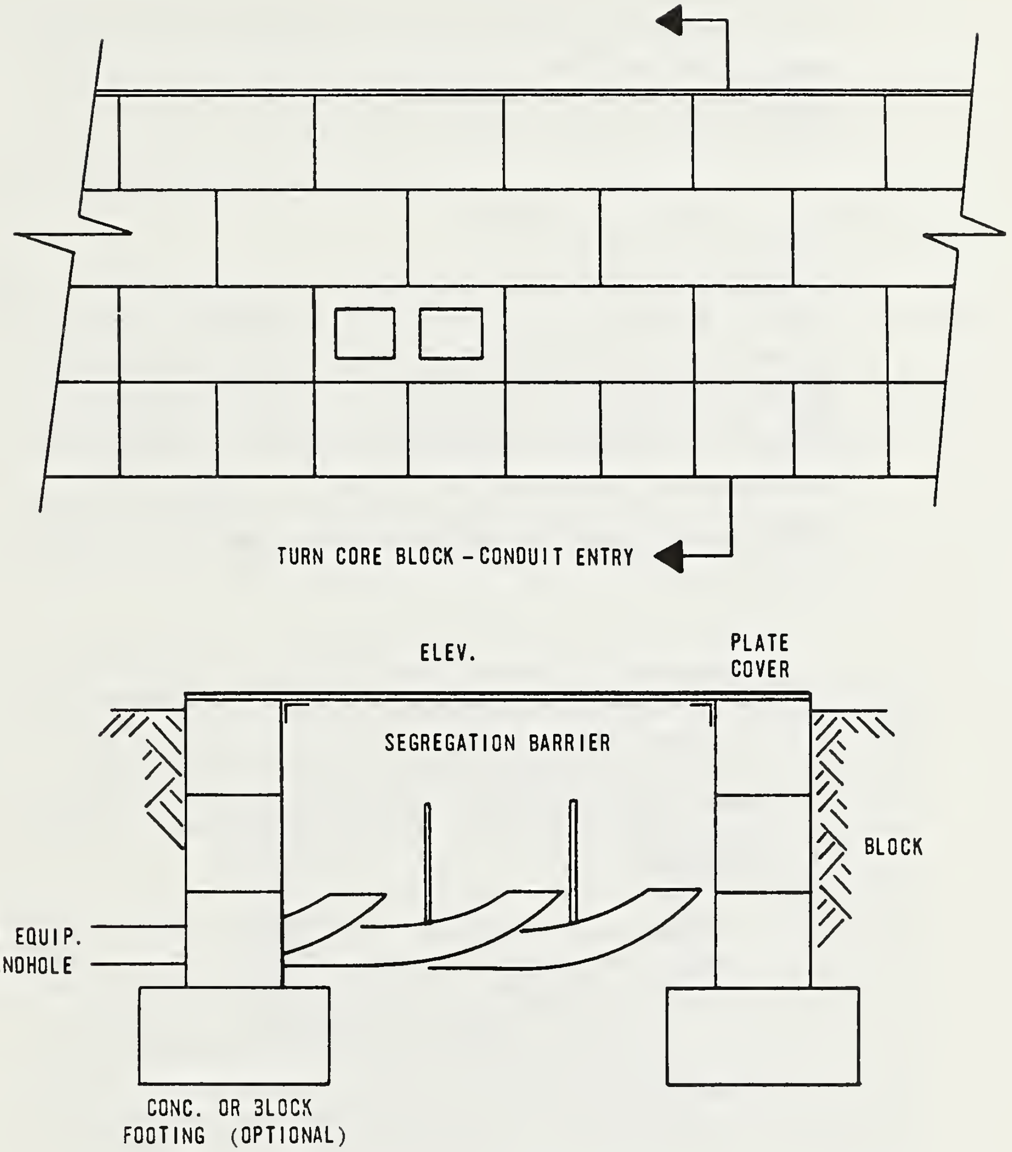


TABLE OF APPROXIMATE CUBIC YARDS OF GROUT FOR 100 TRENCH FEET OF FORMATIONS WITH 3 INCHES OF GROUT ENVELOPE ON BOTH SIDES, THE TOP AND THE BASE.

DUCT FORMATION		A	B	C	D	E	F	G	H	J
NUMBER OF DUCTS		2	3	4	6	8	9	12	16	20
1-1/2 INCH SEPARATION OF CONDUIT										
SIZE OF CONDUIT	2	2.6	3.3	3.6	4.6	5.7	5.9	7.3	8.9	10.5
	3	3.2	4.1	4.5	5.9	7.3	7.6	9.4	11.8	13.7
	3-1/2	3.4	4.5	4.9	6.5	8.0	8.5	10.6	13.0	15.4
	4	3.7	5.0	5.4	7.2	8.9	9.5	11.7	14.4	17.2
	4-1/2	4.0	5.3	6.0	7.9	9.8	10.3	12.9	16.0	19.0
	5	4.4	5.8	6.5	8.6	10.7	11.3	14.1	17.5	21.0

FIGURE X-4

CUBIC YARDS OF GROUT FOR 100 TRENCH FEET



SECTION

FIGURE X-5

BLOCK TRENCH
CAST CONCRETE SIMILAR

b. Cast In Place Concrete Construction

This form of trench construction can be justified in a large substation where many foundations are being constructed and the necessary tradesmen and materials are readily available. Fabrication is similar to the block cable trench illustrated in Figure X-5.

c. Precast Concrete Trench

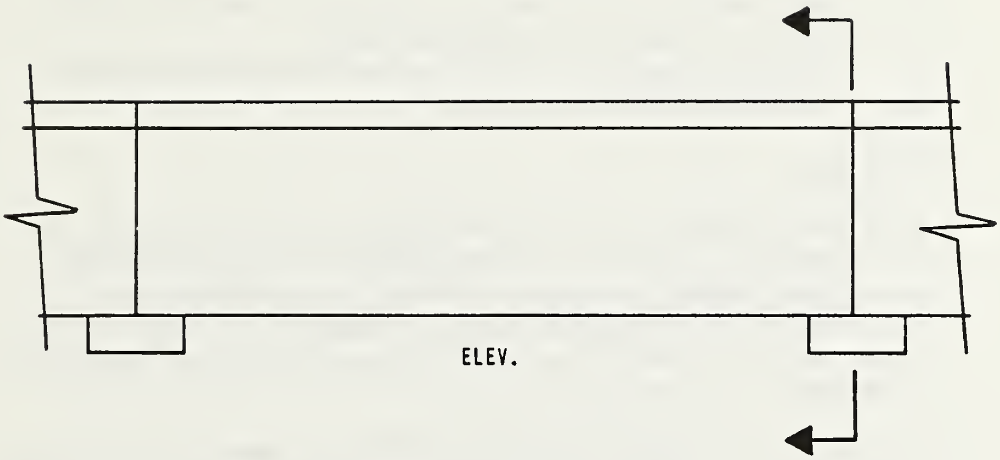
Depending on manufacturing plant locations and related freight cost, precast trench may present an attractive alternate for a reasonably large installation. Field labor should be substantially lower than the block or cast in place options. Precast trench is supplied with light weight concrete covers in manageable lengths depending on trench width. Figure X-6 shows a typical design. Transitions are also available for vehicular crossings and building entrances.

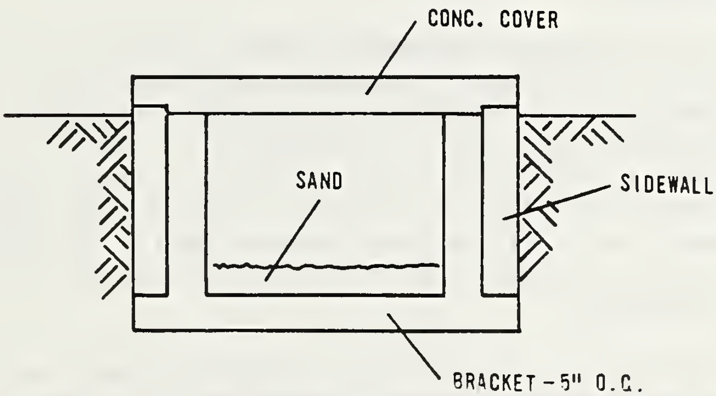
A very high degree of layout flexibility is available to the engineer. Direction changes are usually limited to 90°, but with the cable lay-in benefits, cable damage in construction should be nonexistant. The Engineer can, with different trench widths, layout a complete trench system without costly manhole construction also avoiding substation roadways.

Electrical segregation cannot be as complete with a cable trench system as in a multiple conduit duct bank system. In general, cable trenches are constructed without bottoms or floors. This is done to eliminate floating or frost heaving with consequent misalignment possibility. Cables are placed on a 10.2 to 15.2 centimeter (4 to 6 inch) bed of fine sand. French drains can be placed at selected intervals to drain the trench of storm water.

Advantages

a. Cable is layed-in
b. Cable replacement or addition simplified
c. Expansion is unlimited
d. Electrical segregation possible to a limited degree
e. Layout does not require manholes
f. High degree of installation flexibility





SECTION

FIGURE X-6

ILLUSTRATIVE PRECAST
CABLE TRENCH

Disadvantages

a. Does not prevent cable damage from burrowing animals and rodents
b. Care must be exercised to prevent covers from falling in trench and damaging cable
c. Vehicular traffic over trenches must be prevented
d. Possible drainage barrier

5. Manholes

A companion item to some underground raceway systems is the manhole. Generally used in conjunction with below grade duct banks, a manhole serves as a pulling and splicing point for cable runs, as a point to turn a duct line, and as a place to provide contraction and expansion of power conductors.

In light of the high construction costs even with precast units, and the ease of design and substantially lower cost of a total trench design, details of manholes will not be considered in this guide.

6. Handholes

Unlike manholes, handholes have a definite place in substation design. A handhole is essentially a miniature manhole installed approximately two feet below grade and measuring about two feet square. It serves as a pulling point for cables in a direct burial conduit system. To prevent floating, no bottom or floor is provided. This feature also allows easy conduit entry. A split metal cover or a lightweight concrete cover with knock outs is recommended.

The Borrower, depending on handhole usage, may elect to design forms and produce handholes. An outside small business firm could also be contracted to perform this service.

Figure X-7 shows a suggested handhole design which the Borrower can size to his particular requirements.

G. RACEWAY COMBINATION

In all but the simplest installation, the designer will be confronted with combinations of the below grade systems outlined in this chapter. Such combinations are the usual practice in substation design.

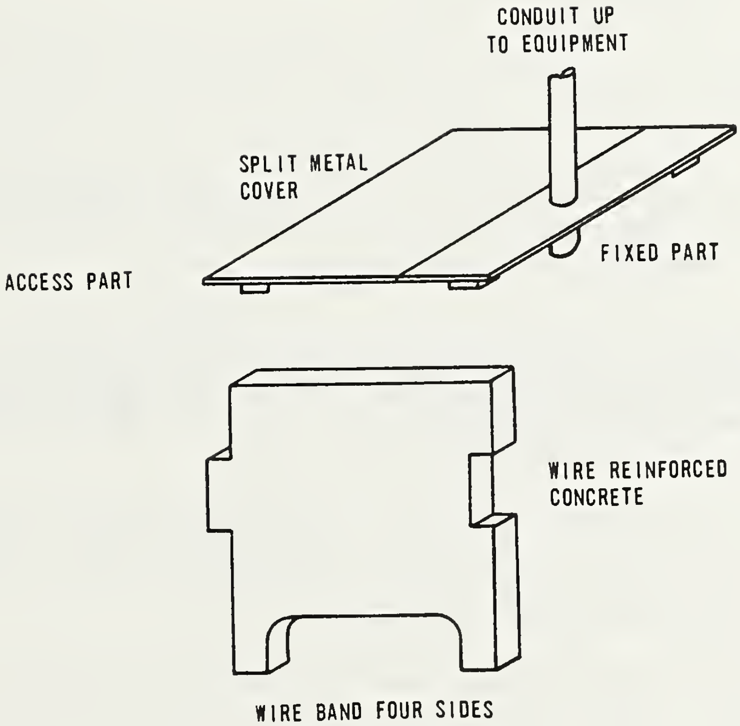


FIGURE X-7

SUGGESTED HANDHOLE DESIGN

The specific combination used in a given substation could possibly vary by geographic location. The most common system is one using cable trench, direct buried conduit, handholes, and conduit rises. Figure X-8 shows a typical system.

H. SUMMARY - UNDERGROUND RACEWAYS

If direct burial cable is under consideration for a small installation, it should be recognized that a treated plank over the cable can offer some cable protection. Additionally, markers are available to indicate the cable route. The best protection against accidential "dig-in" is to maintain accurate, up to date drawings and set up a control system for all excavation within a substation enclosure. See REA Bulletin 61-15 regarding protective planks.

When showing duct elevations on a construction drawing, the invert elevation (inside bottom edge of duct) should be indicated rather than the centerline. If the centerline is shown, the duct radius must be subtracted to arrive at the invert. This introduces the possibility for error.

Precast concrete duct sections are available under various trade names. These products make excellent raceways. However, site handling costs should be determined, as the weights of the raceway components are high.

The concrete encased duct system will find limited use in all but the very largest substations and then under heavy axle bearing roads. Heavy wall, direct burial, PVC conduit, 36 in. below a substation road surface will successfully withstand most substation vehicular traffic depending on soil conditions.

The possibility of burrowing animals causing cable damage in trenches has been mentioned. With a knowledge of the area, the Borrower should take this situation into account when selecting site surface stone size and depth. The animal problem can be eliminated with adequate surface preparation.

Trapping or low points of below grade conduits should be avoided in the design phase.

The Borrower and Engineer should avail themselves to the many handbooks and other material available from vendors of raceway materials.

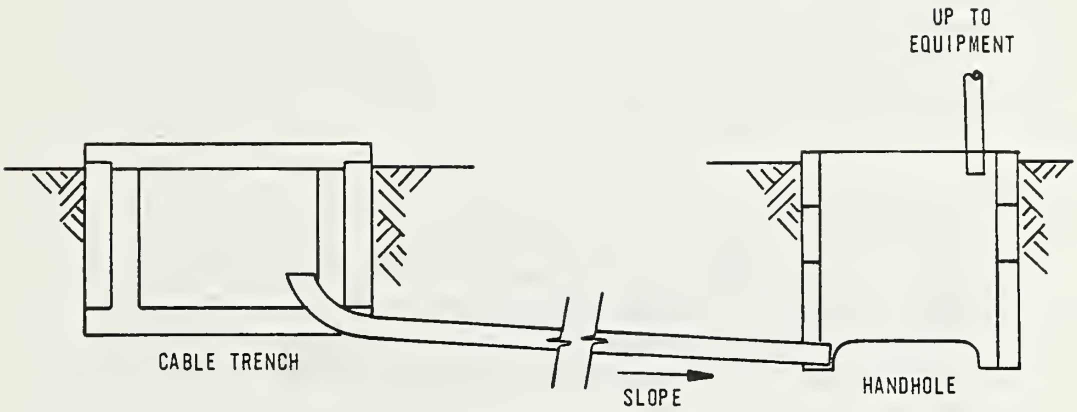


FIGURE X-8

TRENCH TO HANDHOLE
CONDUIT INSTALLATION

I. OVERHEAD RACEWAYS

In cases where buried raceway systems are impossible or unnecessary, above grade raceways can be considered.

Available overhead raceways are:

1. Cable tray
2. Cable duct
3. Plastic conduit
4. Metal conduit
5. Above grade cable trench

1. Cable Trays

Cable trays offer ease of installation and circuit segregation within one tray. Attention must be given to mounting details to prevent weather damage. Substation structures and/or specially designed support structures can be used.

Solid bottom tray with expanded metal covers should be specified to prevent bird nesting. Access for equipment removal must be considered in the design phase.

2. Cable Ducts

Cable duct consists of cable tray fitted with wooden blocks to properly space and support power conductors, in the 600 - 15000 volts range. Application in a substation would be limited to incoming or exiting distribution circuits.

3. Plastic Conduit

Plastic conduit and fittings are available from several manufacturers to meet the requirements of the N.E.C. Installation of this conduit has a labor advantage over steel, four inch steel weighing 14.9 kilograms per meters (10 pounds per foot), componed to plastic weighing 3.0 kilograms per meter (2.0 pounds per foot). An adequate variety of fittings and bends are available and joining is done with a cement. Threading is not required. Support requirements are outlined in the N.E.C.

4. Metal Conduit

Metal conduit comes in three types, electrometallic tubing (thin wall), galvanized steel (heavy wall), and aluminum.

Thin wall is limited to two inch diameter and fittings are expensive. The two inch size weighs 0.21 kilograms per meter (0.14 pounds per foot) as componed to 4.9 kilograms per meter (3.3 pounds per foot) for steel. Gland type fittings are available to provide weather tightness.

Galvanized steel conduit, available in trade sizes from 1/2 inch to 6 inch will provide the best mechanical protection for control and power cables. However, labor cost is high. Cutting, threading, and bending require tools not usually owned by tradesmen. The best application in a substation for this conduit is for serving lighting and convenience outlets with conduit clamped to structural members. Outdoor fittings and luminaires are threaded for 1/2 inch and 3/4 inch rigid conduit. Aluminum conduit offers weight advantage in large sizes. Additionally, if each phase is installed in a separate conduit, aluminum will not heat up as will steel. Aluminum conduit should not be installed below grade, either for direct burial or concrete encasement because of possible corrosion damage.

5. Above Grade Cable Trench

A cable trench of block, cast in place, or precast concrete construction is satisfactory for above grade raceways. Construction would be identical to a below grade trench. In the case of precast construction the "bracket" would have a 1/2 inch threaded insert and the side walls each would have a half hole on each end. A 1/2 inch bolt and square washer would hold the wall in place in lieu of backfill. This construction method is not recommended where ground is subject to severe frost movement.

J. SUMMARY - OVERHEAD RACEWAYS

Where undergrounding is not possible and substation control is sophisticated, cable tray anchored to the substation equipment supports and/or above grade trestles should be considered. The tray could be selected to provide circuit segregation. Grounding of non current carrying metal parts such as exposed cable tray is necessary and is covered in Chapter IX.

In the simplest temporary substation, plastic conduit would require the least labor time. Under some conditions, the conduit could be installed on top of the site stone.

K. RACEWAY MATERIALS

1. Plastic

Plastic conduit, as currently available, covers an extensive list of organic materials with a variety of wall thickness, degrees of flexibility, available lengths, diameters and applications.

The "Thermoplastic Conduit, Duct and Accessories Section" of NEMA prepares a chart of duct types, characteristics, and applications. This chart also shows the codes and standards met by the listed conduit types. Manufacturers of this material publish copies of this chart which should be readily available.

2. Fiber

Fiber conduit is a smooth bore duct made of wood pulp pressure felted on a rotating mandrel, dried and vacuum impregnated with hard coal tar pitch. The ends of eight foot lengths are tapered as are couplings. Cutting can be done with a coarse tooth hand saw and a factory quality taper is easily accomplished with a tapering tool.

The material is manufactured with wall thickness for direct burial or concrete encasement. Angle couplings, bends and offsets are available. Adapters for joining to threaded steel, reducers, and caps are stock items with many distributors.

Manufacturer's data and detailed installation instructions are easily obtained.

3. Cement Asbestos

Cement asbestos conduit, except for the inorganic material, is essentially the same as fiber conduit. It has one drawback. It should be cut with a high speed power saw (3450 rpm) and if extensive cutting is to be done, the machine should be equipped with a vacuum collector and the tradesman should wear a suitable mask.

A plus factor for this type duct is its fire resistant property. There have been cases, using fiber, where a

sustained, uncleared power cable fault has melted the pitch, blocked the duct and made it unusable for a new cable.

L. RACEWAY SIZING

Raceway sizing is an important parameter in substation design notably for a large installation. When laying out the underground system, it is important to visualize the station as it will be as expanded, possibly to the ultimate configuration.

In sizing of individual conduits of the system, good practice indicates 40 percent maximum fill for each conduit. This means the total cross sectional area (over insulation) of all conductors in a conduit should not exceed 40 percent of the cross sectional area of the interior of the conduit or duct. As an example a four in. conduit has an internal area of 12.72 sq. in; hence, at 40 percent fill, the total conductor area should not exceed 5.09 sq. in. This practice is allowed by the N.E.C. and refers to single ducts.

In the planning stages, the ultimate substation must be visualized and duct banks sized to provide for all required cables, remembering that all control cables substation originate at the control house. Duct exits should be provided for ultimate requirements.

Previously it was noted that underground duct bank application is decreasing in substation expansion and new substation design, giving way to cable trenches. When the uncertainties of below grade duct bank design for a future expansion program are considered, cable trench becomes a viable alternative.

The N.E.C. outlines the sizing of cable tray. The same article can be used as a guide for cable trench sizing. The limits in the article can be exceeded within reason, due to the trench being located out-of-doors with normally lower ambient temperatures than indoor tray.

CHAPTER XI - CORRODSION

A. GENERAL

Corrosion is the destruction of a metal by chemical or electrochemical reaction with its environment. The electrode at which chemical reduction occurs is called the cathode (positive current enters the cathode from the electrolyte). The electrode at which chemical oxidation (corrosion) occurs is called the anode (positive current leaves the anode and enters the electrolyte).

Two of the most common corrosion cells encountered result from dissimilar metals in the same environment or the same metal in dissimilar environments. An example of the first corrosion cell would be an underground bare copper cable and a galvanized conduit buried in the ground inside a substation. It is necessary that these metals be connected together electrically to complete the corrosion cell. An example of the second corrosion cell would be a tinned copper concentric neutral running through soils of different resistivities, different pH's, different aeration levels or combinations of these.

1. Dissimilar Metals

When two dissimilar metals are placed in the same environment, there will be a difference in dc voltage because of the different activity levels that the metals occupy in the Electromotive Force Series. In a typical substation, a voltage difference in the order of one volt will probably exist between a copper ground cable and galvanized steel structures and a dc corrosion current will flow from the steel. The current will be limited by the resistance between the structures in accordance with Ohm's law and also by surface films which may greatly reduce the current and the rate of corrosion.

2. Dissimilar Environments

Differences in dc potential along the ground grid conductors or concentric neutrals can be caused by varying oxygen concentrations, different values of pH, or because the soil resistivity varies over a fairly wide range. In this case, the corroding areas may be at random locations that would have to be located.

For a more detailed treatment of basic corrosion theory, see the attached Bibliography.

B. PRELIMINARY PREVENTIVE MEASURES

1. Surveys

It is important that certain preliminary data be obtained prior to final site selection so that corrosion problems can be avoided or minimized. This procedure insures that design and/or material selection will minimize possible corrosion problems. The preliminary data should include:

a. Soil Resistivity Survey

A soil resistivity survey should be taken at each proposed site. One way to obtain this information would be using the 4-pin method (see Figure XI-1). Data will show the variation in resistivity of the soil and will also prove useful when determining grounding requirements.

b. pH Survey

A pH survey of each substation site should also be a part of any corrosion evaluation.

2. Selection of Materials

Select materials to minimize dissimilar-metal corrosion effects due to buried copper and steel (or other metals) in the same environment. For example, the grounding system at any one substation location should consist wholly either of copper or steel. This is particularly important in corrosive soils such as those with low values of earth resistivity (less than 2,000 to 3,000 ohms-centimeter). No commonly used material can be wholly immune to possible corrosion damage. However, in the absence of a planned maintenance program to periodically determine the specific condition of ground grid conductors, the final choice of material should consider the available, proven historical records of the materials under consideration.

Where buried steel, such as steel anchor assemblies, piping and conduit is of necessity connected to the copper grounding grid for safety, the higher the ratio of steel-to-copper surface area the less likely will be the adverse

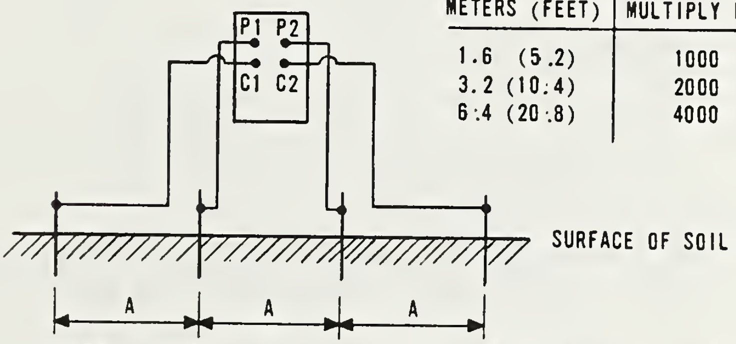
effects of corrosion of the steel. Where the copper grounding system is the only metal placed in the substation soil be alert for possible interconnected steel in nearby line anchor assemblies, piping, wells, conduit, oil or gas lines that may be inadvertently connected to the grounding system and subject to accelerated corrosion. If such conditions exist cathodic protection of the interconnected steel may be necessary. For many rural substations the installation of anodes as outlined in REA Bulletin 161-23 should provide acceptable results. For large substations a rectifier-type cathodic protection scheme may be required.

C. <u>TESTING AND INSTALLATION</u>

1. <u>Earth Resistivity Measurements</u>

Earth resistivity in undisturbed soil may be determined with a four-terminal ground tester and test electrodes places as shown in Figure XI-1.

A METERS (FEET)	MULTIPLY BY
1.6 (5.2)	1000
3.2 (10.4)	2000
6.4 (20.8)	4000



EXAMPLE: FOR A = 3.2 M (10.4 FT), IF METER READS 1.2 OHMS, RESISTIVITY = 1.2 x 2000 = 2400 OHM-CM

<u>FIGURE XI-1 MEASUREMENT OF EARTH RESISTIVITY WITH A FOUR-TERMINAL GROUND TESTER</u>

Stubs of stiff wire, pushed several centimeters into the soil, may be used as test electrodes.

For a proposed substation location, measure the earth resistivity at several locations and record the observations on a sketch of the substation area. The degree of variations will show how many observations are needed for a reliable indication. A distance of 3.2 meters (10.4 feet) between test points, which gives average resistivity to a 3 meter depth and a meter multiplier of 2,000, has been found to be a convenient choice. Avoid test locations close to parts of an existing ground mat or other buried metal.

2. <u>Soil Samples</u>

Obtain soil samples at the approximate depth of the underground structures in the substation. These samples can usually be obtained with a soil auger. A pH reading can be taken immediately, or the soil can be stored in an airtight container such as a plastic bag and the readings taken at a later time. Lower pH values generally indicate more corrosive type soils. These tests can be handled by a testing laboratory or done in-house, by using commercially available soil testing kits.

3. <u>Anode Locations</u>

Sacrificial anodes where used should be placed:

a. At locations of the lowest resistivity soil within or near the substation area.

b. At depths at least equal to those of the ground grid and/or other assemblies to be protected.

c. Three to six meters away from the buried bare conductors or other assemblies, to the extent that space allows.

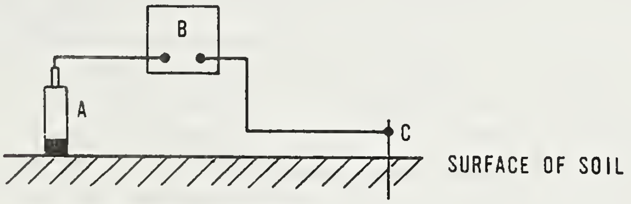
Usual anode locations are at edges or corners of the ground grid, and at structures in low resistivity locations near the substation. The connection from anode to the system neutral and station grid should be reliable and have low resistance. Compression fittings or exothermic-welded connections are preferable to bolted connections or clamps.

4. Underground Connections

Exothermic welding is preferred to clamps or bolted connections for dissimilar-metal (copper-to-steel) connections underground. For similar metal, copper-to-copper or steel-to-steel (galvanized) connections, suitable bolted or clamped connections with clamps of the same material should be satisfactory. Welds should be covered with mastic or other underground coating (such as used for pipelines) in very corrosive soils, with resistivities in the range below 1,000 ohm-cm. In most soils this is not considered necessary.

5. Estimating Corrosion Conditions from dc Potential Measurements

One frequently used indicator of corrosion or freedom from corrosion is the dc potential (voltage) measured from a copper-copper sulfate reference electrode or half-cell. This measurement is made as shown in Figure XI-2.



A: REFERENCE ELECTRODE
B: VOLTMETER
C: GROUND WIRE OR OTHER CONNECTION TO BURIED NEUTRAL

BURIED METAL	TYPICAL POTENTIAL VOLTS
ZINC OR NEW GALVANIZED STEEL	-1.1 OR MORE NEGATIVE
STEEL FULLY PROTECTED AGAINST CORROSION	-0.85 OR MORE NEGATIVE
OLD BURIED STEEL PIPE	-0.65
"COPPER-GROUNDED" NEUTRAL WITH ANCHORS AND STEEL PIPING CONNECTED	-0.50 TO -0.65
ALL-COPPER GROUNDED NEUTRAL	-0.30

FIGURE XI-2 MEASUREMENT OF DC POTENTIAL (VOLTAGE) FOR INDICATIONS OF CORROSION CONDITIONS

The copper-copper sulfate half-cell is a copper rod surrounded by a saturated solution of copper sulfate (blue vitrol) in water, with a porous plug to allow the solution to come in contact with the soil. The voltmeter usually is a potentiometer (null-type) voltmeter or a special high-resistance (10 megohms or higher) low-range voltmeter. However, a useful reading may also be possible with a 20,000 ohm-per-volt dc meter with a 2.5-volt range.

The variations in dc potential are small and often expressed in millivolts. Usually, the neutral is negative with respect to the copper-copper sulfate half-cell. Figure XI-2 lists some typical potentials for metals and combinations of metals that may be present and connected to a substation ground grid.

Potential measurements indicate the effectiveness of anodes for cathodic protection. For example, anodes may be installed at a copper-grounded substation to relieve corrosion of anchor rods near the substation. If the anodes are effective, the station ground grid becomes more negative. The potential might be shifted from -0.55 volt to -0.75 volt. In a situation where original anchor rods have begun to fail after 15 years, such a change in potential should be adequate to assure permanence of the newly-installed anchors. In very corrosive soils (such that anchor rods might otherwise fail in five years or less) a shift to at least - 0.85 volt may be needed for complete protection.

Very little is known about potentials of copper corroding in soil. However, copper corrosion has been observed in a neutral to moderately alkaline soil (pH 7.1 to 8.0) at potentials of -0.10 to +0.047 volt with reference to a copper-copper sulfate half-cell. For the present, if cathodic protection of copper is found to be necessary, a potential of -.35 volt is suggested for purposes of design.

In distribution substations, underground exit feeders with bare concentric neutrals may be vulnerable to corrosion. They should be provided with cathodic protection if the possibility of corrosion is believed to exist.

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CHAPTER XII - PROTECTIVE RELAYING

A. GENERAL

1. Purpose of Protective Relays

Protective relays are used to detect defective lines or apparatus and to initiate the operation of circuit interrupting devices to isolate the defective equipment. Relays are also used to detect abnormal or undesirable operating conditions other than those caused by defective equipment and either operate an alarm or initiate operation of circuit interrupting devices. Protective relays protect the electrical system by causing the defective apparatus or lines to be disconnected thereby to minimize damage and maintain service continuity to the rest of the system.

2. Indications of Defective Equipment or Abnormal Conditions

The most common indications of defective equipment or abnormal conditions are as follows:

a. Short Circuits

A short circuit is an abnormal connection of relatively low resistance between two or more points of differing potential in a circuit. If one of these points is at ground potential, it is usually referred to as a "ground fault." If ground potential is not involved, it is usually referred to as a "phase fault." Phase faults usually cause excessive currents and low voltages. Ground faults may or may not cause excessive currents or abnormal voltages, depending upon whether the system is normally ungrounded, high- or low-resistance grounded, or effectively grounded.

b. Excessive Heating

Equipment is designed to deliver full-rated capacity with the temperature maintained below a value that will not be damaging to the equipment. If operating temperature becomes excessive, the life of the equipment (generator, motor, transformer, etc.) will be

reduced. Excessive heating may be caused by overloading, high ambient temperatures, improper cooling or failure of cooling equipment.

c. Overvoltage

Equipment is designed for normal operating voltages as stated on its nameplate with a slight allowance (usually about five percent) for normal overvoltage. Abnormal overvoltage may cause: (1) insulation failure; (2) shortening of the equipment life; (3) excessive heating due to greatly increased excitation currents where electro-magnetic devices are used; (4) excessive heating in resistors used in controls; and (5) failure of transistors and other electronic devices.

d. Undervoltage

Continued undervoltage will cause overheating of motors, dropping out of contactors, and failure of electrical equipment to function.

e. Unbalanced Phase Conditions

On balanced three-phase systems with balanced three-phase loads, a sudden unbalance in either or both the current and voltages usually indicates an open or a partially shorted phase. An unbalanced voltage condition is especially serious for three-phase motors because negative sequence currents can lead to considerable overheating within the motor. On balanced three-phase systems with single-phase loads, the loading on each phase may normally vary, depending upon the magnitude of each single-phase load. However, it is desirable to keep this unbalance to a minimum to maintain balanced voltages for three-phase loads.

f. Reversed Phase Rotation

Reversed phase rotation can occur after circuit changes have been made or during an open phase condition. Reversed rotation of motors may cause considerable damage to the facility driven by the motors, such as a conveyor.

g. Abnormal Frequency

Abnormal frequencies can occur when the load does not equal the generation. Many facilities such as electric clocks, synchronous motors, etc., are frequency sensitive.

h. Overspeed

Considerable mechanical damage can be done to generators and motors because of overspeed. Excessive overspeed may cause parts of the generator or motor to be thrown for considerable distances, and is dangerous to personnel as well as to other facilities. Generators or series connected motors may reach dangerous overspeeds when loads are suddenly removed.

i. Abnormal Pressure

In electrical equipment, such as transformers, that use liquid as an insulating fluid, high internal pressures can be created during internal faults.

B. BASIC RELAY TYPES

1. General

Most types of protective relays consist of a detecting element with contacts. Electromechanical detecting elements usually operate on the magnetic attraction principle, the electric heating principle, or the electromagnetic inductive principle (as used in motor operation) to open or close contacts. Static or solid state detecting elements generally convert the current, voltage or power inputs to proportional dc millivolt signals that are then applied to adjustable transistor amplifiers. These amplifiers have a "go-no go" characteristic where an input up to the set level produces no output and inputs beyond that level produce full output. The output may be another dc millivolt signal to apply to more transistor logic or it may be a contact closure. The detecting element is set to respond to specified magnitudes or relationships of electrical quantities and cause the contacts to close. Relays may operate (1) instantaneously, (2) with some definite time delay, or (3) with a time delay that varies with the magnitude of the quantities to which the detecting element responds. The quantities to which the relay responds usually designate the relay type.

2. Overcurrent Relay

The overcurrent relay responds to a magnitude of current above a specified value. There are three basic types of construction: plunger, rotating disc and static. In the plunger type, a plunger is moved by magnetic attraction when the current exceeds a specified value. In the rotating induction-disc type, which is basically a motor, the disc rotates by electromagnetic induction when the current exceeds a specified value. Static types convert the current to a proportional dc millivolt signal and apply it to a level detector with voltage or contact output. Such relays can be designed to have various current versus time operating characteristics. In a special type of rotating induction-disc relay, called the voltage restrained overcurrent relay, the magnitude of voltage restrains the operation of the disc. Static overcurrent relays are equipped with multiple curve characteristics and can duplicate almost any shape of electromechanical relay curve.

3. Distance Relay

The distance relay responds to both voltage and current. The voltage restrains operation, and the current causes operation that has the overall effect of measuring impedance. The relay operates instantaneously (within a few cycles) on a 60 cycle basis for values of impedance below the set value. When time delay is required, the relay energizes a separate time delay relay with the contacts of this time delay relay performing the desired functions.

4. Differential Relay

The differential relay responds to the difference between two or more currents above a specified value. It is used to provide internal fault protection to equipment such as transformers, generators, and buses.

5. Overvoltage Relay

The overvoltage relay responds to a magnitude of voltage above a specified value. The basic types of construction are the plunger, rotating induction-disc and static, all of which are discussed in Paragraph B-1.

6. Undervoltage Relay

The undervoltage relay responds to a magnitude of voltage below a specified value and has the same basic construction as the overvoltage relay.

7. Power Relay

A power relay responds to the product of the magnitude of voltage, current, and the cosine of the phase angle between the voltage and current, and is set to operate above a specified value. The basic construction is usually that using the rotating induction-disc principle. The relay is inherently directional in that the normally open contacts close for power flow in one direction above a set value but remain open for power flow of any amount in the opposite direction.

8. Directional Relay

A directional relay is a relay that operates only for current flow in a given direction. An overcurrent relay is made directional by adding a directional unit that prevents the overcurrent relay from operating until the directional unit has operated. The directional unit responds to the product of the magnitude of current, voltage, and the phase angle between them, or to the product of two currents and the phase angle between them. The value of this product necessary to provide operation of the directional unit is small, so that it will not limit the sensitivity of the relay (such as an overcurrent relay that it controls. In most cases, the directional element is mounted inside the same case as the relay it controls. For example, an overcurrent relay and a directional element are mounted in the same case, and the combination is called a directional overcurrent relay.

9. Frequency Relay

A frequency relay responds to frequencies above or below a specified value. The basic types are vibrating reed, rotating induction-disc with a frequency sensitive circuit, and static.

10. Thermal Relay

The thermal relay responds to a temperature above a specified value. There are two basic types: direct and replica.

a. Direct Type

In the direct type of thermal relay, a device such as a thermocouple is imbedded in the equipment. This device converts temperature to an electrical quantity such as voltage, current, or resistance. The electrical quantity then causes a detecting element to operate.

b. Replica Type

In the replica type of thermal relay, a current proportional to the current supplied to the equipment flows through an element, such as a bimetallic strip, that has a thermal characteristic similar to the equipment. When this element is heated by the flow of current, one of the metallic strips expands more than the other. This causes the bimetallic strip to bend and close a set of contacts.

11. Pressure Relay

The pressure relay responds to sudden changes of either fluid or gas pressure. It basically consists of a pressure sensitive element and a bypass orifice, located between the equipment to which the relay is connected, and a chamber that is part of the relay. During slow pressure changes, the bypass orifice maintains the pressure in the chamber to the same value as in the equipment. During sudden pressure changes, the orifice is not capable of maintaining the pressure in the chamber at the same value as in the equipment, and the pressure sensitive element mechanically operates a set of contacts.

12. Auxiliary Relay

Although they may be an integral part of any relaying scheme, auxiliary relays are generally not used to initiate action. Instead, they perform such functions as time delay, counting, and providing additional contacts upon receiving a signal from the initiating relay. These relays are necessary to provide the broad variety of schemes required by a power system.

C. RELAY SCHEMES

1. General

Protective relays are most often applied with other protective and auxiliary relays as a system rather than individually. Electromechanical systems are interconnected through contacts and are easily modified in the field. Static systems are composed of three basic elements: detecting, logic and output. The detecting elements convert the power system quantities to dc millivolt signals that are then applied to the logic elements. The logic circuits make the decision to trip or not to trip and pass trip or alarm commands to the output elements, which reconvert the dc millivolt signals to higher energy control quantitites.

The following basic scheme descriptions apply to both electromechanical and static systems. The static systems generally have more elaborate logic involved in the tripping decision, particularly in the area of transient blocking during external fault clearing. Static systems require more careful treatment of input circuits; i.e., ct and pt leads are often shielded. Static systems are slightly faster, require less maintenance, and are considerably more costly.

2. Transmission Line Protection

a. Piloted Schemes

Two major modes of protection are piloted and non-piloted schemes. Piloted schemes measure system parameters at both local and remote terminals, simultaneously monitor them and then respond according to their predetermined functions. These schemes require the use of a communications medium such as pilot wires, microwave or power line carrier. Non-piloted schemes measure system parameters at local terminals. If these parameters vary from the desired norms, appropriate actions are initiated.

(1) Phase Comparison

Phase comparison relay systems indicate the current direction at each end of the protected line and transmit this information to the other end via a communication channel. Each end

compares local and remote current direction, and trips if the current is into the line from both ends. This system is immune to tripping on overloads or system swings, since it operates on current direction only. It needs no potential source unless it must be supervised by distance relays because of low fault currents.

Current or distance fault detectors are used to supervise tripping. These detectors must be set above line charging current, which can appear to the relays as an internal fault at low loads. Internal timers must be set to compensate for the transit time of the communications channel. One of the most popular applications of this system is on lines with series capacitors because it is less likely that such a current operated scheme will operate incorrectly for faults near the capacitors.

(2) Directional Comparison

Blocking directional comparison uses distance relays as directional indicators and block initiation for phase faults. Each terminal has trip and start relays. The trip relay reaches toward the remote terminal and a little beyond. The start relay reaches backwards, away from the protected section. The trip relay attempts tripping when it operates unless it is stopped by receipt of a blocking signal (carrier, audio tone or microwave) from the remote end. The start relays at each end initiate the blocking signal. Thus, if only the trip relays see the fault, it is within the protected section and both ends trip. If the fault is just outside one end, the start relays at that end operate and send a block signal to the remote end, which would otherwise trip. The ground relays operate in a similar manner, except that some ground relays use directional overcurrent instead of distance detectors.

Unblocking directional comparison is essentially identical, except that the start relays are deleted and the block signal is sent continuously. To trip, the block signal is then interrupted.

Blocking directional comparison is commonly used with on-off type carrier facilities, and unblocking directional comparison uses a frequency shift keyed channel. Since it is not necessary to drive a signal through a fault to operate this scheme, it is the most popular carrier relaying system. See Figure XII-1.

(3) Direct Underreach

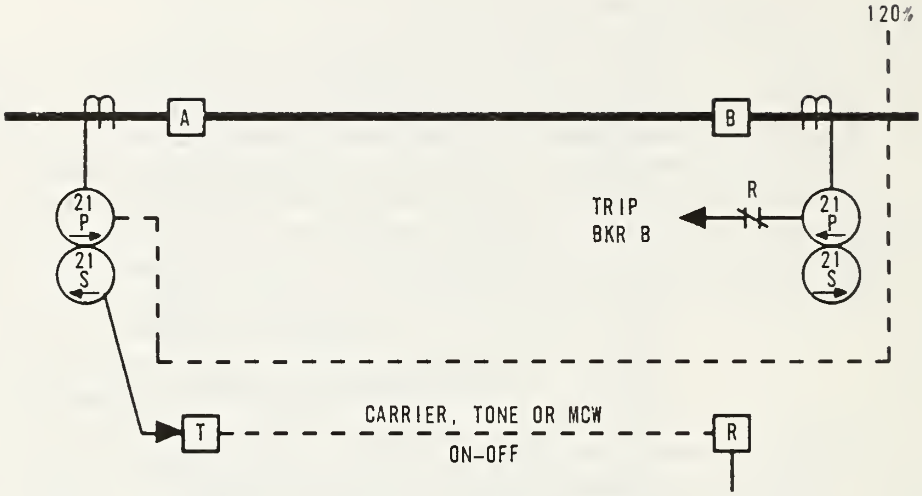
This form of protection requires only a single distance fault detector at each end. It must be set short of the remote end and will simultaneously trip the local breaker and send a trip signal to the remote end, which then trips directly upon receipt of the signal. Note that local confirmation is not required upon receipt of a trip signal. For this reason, this is the least secure of the piloted schemes and is generally applied only in cases where a shunt reactor is present and transfer tripping is required for reactor faults. It requires a secure frequency shift keyed channel and is more commonly applied with microwave or audio tone channels than a carrier. See Figure XII-2.

(4) Permissive Underreach

This scheme is identical to the direct underreach scheme with the addition of an overreaching fault detector. The transfer trip signal requires local confirmation by this fault detector before tripping can occur. This increases the security of the scheme and the consequent range of application. It is commonly selected when an existing step distance relay line is to have the carrier added. See Figure XII-3.

(5) Permissive Overreach

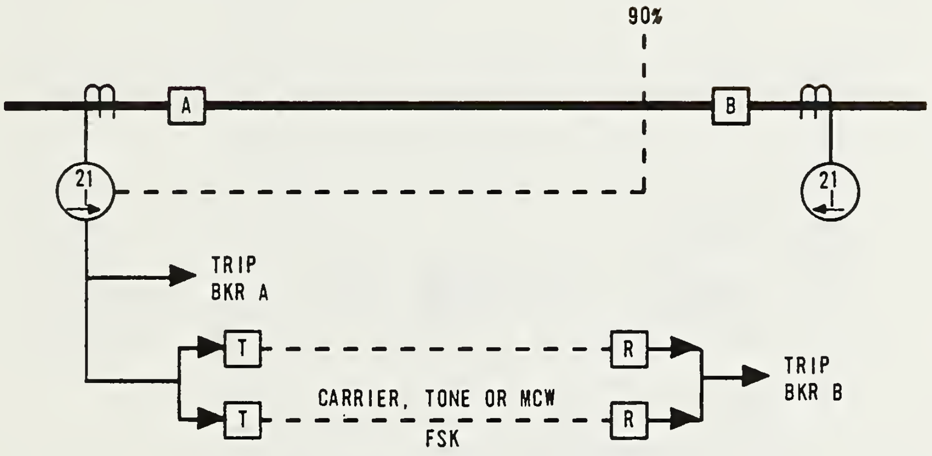
Permissive overreach is also a simple scheme, requiring only one overreaching fault detector at each terminal. This fault detector both sends a trip signal and attempts local tripping through a contact on the receiver. If both relays see a fault, both ends trip simultaneously. It is less secure than directional comparison



TRIP IF:

LOCAL 21/P OPERATES AND CARRIER IS NOT RECEIVED

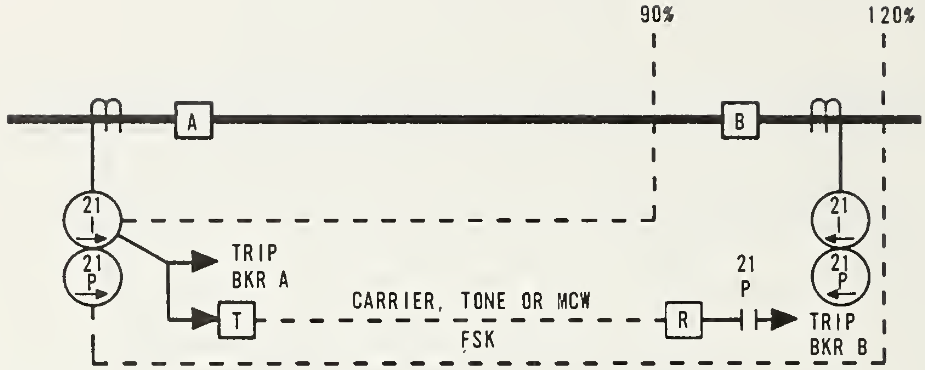
FIGURE XII-1 BLOCKING DIRECTIONAL COMPARISON



TRIP IF:

1. LOCAL 21/I OPERATES OR
2. TWO T/T SIGNALS ARE RECEIVED

FIGURE XII-2 DIRECT UNDERREACH



TRIP IF:

1. LOCAL 21/I OPERATES OR
2. LOCAL 21/P OPERATES AND 1 T/T SIGNAL IS RECEIVED

FIGURE XII-3 PERMISSIVE UNDERREACH

and also is often used when an existing nonpiloted scheme has piloting added. See Figure XII-4.

(6) Pilot Wire

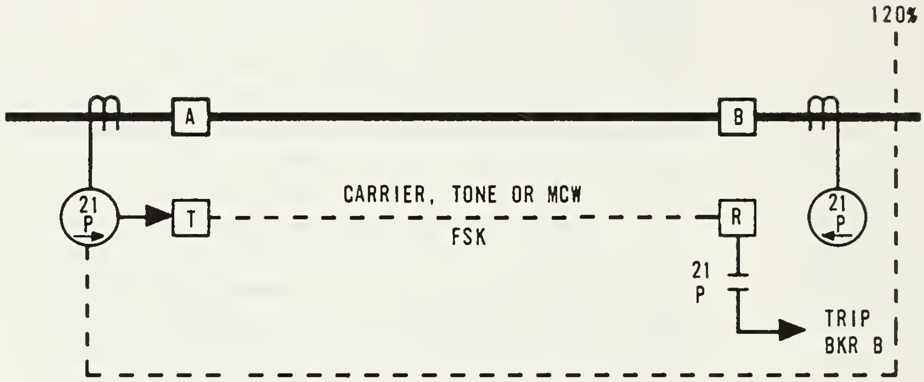
This scheme is similar to phase comparison in that it compares current direction at each terminal but, in this case, the communication channel is a pair of telephone wires. A special filter in the relay converts the three phase currents to a single phase voltage and applies this voltage to the wires. When current flows through the protected section, the voltages at each end oppose each other and no current flows in the operate coils. When current enters the line from each end, the voltage on the pilot wire reverses to allow current to circulate through the operate coils and consequently trip both ends. Special monitor relays sound an alarm if the pilot wire pair becomes open or shorted. The wire line must have adequate protection against induced voltages and a rise in station ground potential but may not use carbon block protectors because the line must remain in service while the protection is operating. Neutralizing transformers and gas tubes with mutual drainage reactors, all with adequate voltage ratings comprise the preferred pilot wire protection package.

This relaying has the advantage of simplicity and does not require a potential source. It does not provide backup protection. Its application is limited to short lines a mile or so in length because of pilot wire cost and increased exposure.

b. <u>Non-Piloted Schemes</u>

(1) Step Distance Relaying

Where piloted relaying is not justified, but more accurate protection than overcurrent relaying is required, step distance protection can suffice. This is simply several (usually three) distance



TRIP IF:

LOCAL 21/P OPERATES AND 1 T/T SIGNAL IS RECEIVED

FIGURE XII-4 PERMISSIVE OVERREACH

relays on a line terminal, each set for a progressively longer distance and trip time as follows:

Zone 1 - 90 percent of line - instantaneous

Zone 2 - 120 - 150 percent of line - 18 - 30 cycles

Zone 3 - 200 percent up - 60 - 120 cycles

Thus, a fault just beyond the remote terminal that is not cleared by its own breaker is cleared by the remote zone 2 in 18-30 cycles. A fault further out on the line will clear in zone 3 time. Zone 3 is usually set to reach as far as possible to cover breaker failures and so is limited by load impedance and susceptibility to swings. Caution must be used, however, when incorporating third zone relays since long settings can result in tripping on load.

(2) Overcurrent Relaying

This simplest form of protection is usually applied on lower voltage lines or on radially supplied feeders. In its most basic form, nondirectional inverse time overcurrent relays are applied on radial feeders with two phase devices and one ground device. The farther out on the feeder the fault occurs, the lower the current seen by the relays and the longer the time required to trip. If backfeed is possible on the feeder, the directional overcurrent relays may suffice. Instantaneous attachments are used where possible to speed clearing time for close-in faults. These are clapper-type relays with adjustable core screws and are set so they cannot trip for a fault on the remote bus.

While this type of protection can be used on a network system with varying contributions from both directions on the lines, it is extremely difficult to coordinate such a system and it should be avoided where possible.

c. Reclosing

(1) General

Protective relays detect faults or abnormal conditions. These faults or abnormal conditions can be transient or permanent. For open-wire overhead circuits, such as most of the distribution lines, most faults are transient faults, caused for example by lightning, that can be cleared by disconnecting the circuit from the power source. Service can be restored by reclosing the disconnecting device. Certain abnormal conditions, such as overheating of motors, can be relieved by reducing the load on the motor. The motor starters thus can be safely reclosed after the motor has cooled off. The disconnecting device can be reclosed either manually or automatically. Manual reclosing is performed by following the same procedures used in closing the device. Automatic reclosing is usually performed by automatic reclosing relays.

(2) Automatic Reclosing Relays

Automatic reclosing relays permit the circuit disconnecting device, usually a breaker, to close one or more times when the breaker has been tripped by protective relays. Relays that permit one reclosing operationg are called single-shot reclosing relays, while relays that permit more than one reclosing operationg are called multishot reclosing relays. Single-shot reclosing relays can be either the manual- or self-reset type. The manual-reset types must be manually reset after each automatic reclosing operation to obtain succeeding automatic reclosing operations. The self-reset types automatically reset if the breaker remains closed for a predetermined time. Multishot reclosing relays are of the self-reset type. Automatic reclosing can take place either instantaneously or with time delay, when the line is deenergized or energized, or when the voltages on both sides of the breaker are synchronized. On radial circuits, the first reclosure is usually instantaneous, with additional reclosures, when used, taking place after some time delay. On loop or multiterminal

distribution lines, instantaneous reclosing is generally not used unless special forms of protective relaying are applied to ensure simultaneous operation of all line breakers for all line faults.

Reclosing is generally not applied where permanent faults are more likely, such as on cables. After a specified number of unsuccessful automatic reclosure attempts, the breaker is usually locked open.

d. <u>Coordination</u>

When a circuit element, such as a line, transformer or bus, becomes faulted, it must be removed from service. This, as has been previously stated, is the function of the protective relay system. Coordination is the process of ensuring that only those elements of the power system that must be removed to clear the fault, and no more, are tripped in the shortest time possible.

Coordination with distance relays is the easiest to accomplish. Since such a relay's reach is constant under all system conditions, the instantaneous zone is typically set short of the remote end of the line by 10 percent and it will never trip for any condition but a fault on the protected section. With the remote end set the same, 80 percent of the line is thus covered by instantaneous protection. To cover the remaining 20 percent, the second zone can be relied on or a piloted scheme can be added. The second zone reaches beyond the protected section and so must have a time delay to allow a breaker at the remote station to clear a fault on another line. The third zone reaches beyond the remote second zones and so must time coordinate in the same manner, Hence, the increasing time settings.

Coordinating with overcurrent relays can be more difficult and can also require a more detailed knowledge of system parameters.

For the simple system shown in Figure XII-5, with a fault at X, the near relays at C and D must operate and their breakers must be completely open before the

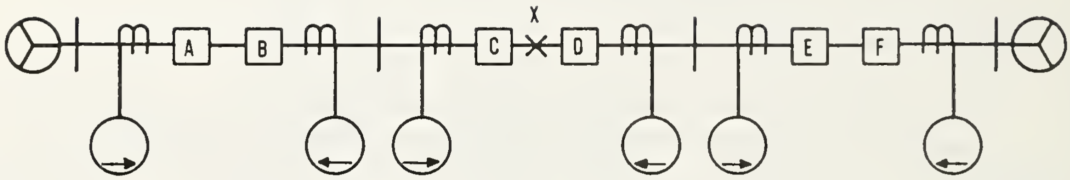


FIGURE XII-5 COORDINATION CONDITIONS

remote or backup relays at A and F close their contacts. It is assumed:

(1) That a faulted condition exists until the breakers isolating the fault are entirely open.

(2) That when a relay closes its tripping contacts, a "seal in" auxiliary relay ensures that the switching operation will be completed even though the fault is cleared at the same instant that the relay contacts close.

The time delay of the remote relay necessary for selectivity must be equal to the operating time of the near relay plus the opening time of the breaker plus a reasonable factor of safety, which can be taken at about 25 percent of the combined relay and breaker time with a minimum allowance of not less than six cycles if the relays are normally field calibrated at the calculated setting. If the relays are bench tested at typical setting values and only adjusted in the field with no further calibration, this margin must be greater, typically 0.2 - 0.3 seconds.

Additional requirements for adequate relaying are:

(1) That the relays be capable of carrying a reasonable emergency overload without tripping incorrectly on load current.

(2) That the relays be able to operate under minimum system generating conditions for faults at the far ends of the sections that they protect.

Maximum system generating conditions include a sufficient number of generators in service to supply the maximum load demand of the system. Similarly, the minimum system generating conditions include only the generators in service necessary to supply the minimum system load. Such minimum conditions would probably exist early Sunday mornings, for example. In addition to the above generation, there are usually some emergency generators in service called "spinning reserve" that can immediately pick up load if a generator fails. Both maximum and minimum conditions must be checked, since maximum generation usually results in faster operation of induction type relays

with more critical selectivity, and the minimum condition determines whether the relays will receive sufficient current to operate.

The output of a synchronous generator under fault conditions is variable depending on the characteristics of the machine and the duration of the fault. The initial output, which is maintained for three cycles or less, may be four to ten times the normal machine rating and is determined by the <u>subtransient reactance</u>. The generator output rapidly decreases to the value determined by <u>transient reactance</u>, the average value of which may be assumed to exist for about 30 cycles on turbine generators and up to 120 cycles on condensers and slow speed generators. The transient reactance may be taken roughly as 125 percent to 150 percent of the subtransient reactance. If the fault is not cleared, the generator output approaches the synchronous value, which is equal to or slightly less than the normal rating. It is the common practice, therefore, to use generator subtransient reactance values when calculating maximum fault kVA and to use transient values for minimum generating conditions. Synchronous values of short circuit kVA are not usually calculated, but the decrease in generator output should be considered for slow operating relays.

For ground current calculations and determination of selectivity for ground relays, it is customary to show only the maximum fault conditions on transmission systems. On transmission systems where the relative distribution of ground fault current is changed for minimum generation because grounded transformers have been removed from service, it may be necessary to calculate and check the relay settings for both maximum and minimum ground faults. It may also be necessary to show minimum ground faults for some special conditions with certain lines or transformer banks out of service.

Briefly summarized, the job of the relay engineer is to assume various types of faults at numerous points on a system. The magnitude and distribution of fault currents are then calculated for these fault points with maximum and minimum generating conditions. Faults are assumed for normal system operating conditions and for various special conditions with certain lines, generators or transformers out of service.

The operating time of all breakers involved must be checked and tabulated and, for high burdens or low ratios, the true or effective ratios of bushing type current transformers must be determined. Having obtained these data, the next step is to determine suitable settings or adjustments for the relays that will provide selective operation for each fault condition. The tentative relay settings, the calculated current values and the operating times of the near and remote relays for each fault condition are worked up and recorded as "Details of Selectivity" or on "Selectivity Curves." After the most satisfactory settings are determined, "Summary Sheets" are made up for all the relays at each station. The Summary Sheets have the instructions or calibration data to enable the relay men in the field to set or adjust the relays to obtain the desired operating characteristics.

3. Transformer and Reactor Protection

The larger size transformers, 30,000 kVA and above, should be protected by differential relays, sudden pressure relays, directional phase distance relays, and ground-overcurrent relays. Transformers with 10,000 - 20,000 kVA ratings may or may not have differential protection. Each such installation should be individually evaluated. Transformers rated 10,000 kVA or below are usually protected by high-voltage side fuses. Reactors may be protected by generator type differential relays with phase and ground overcurrent backup relays. Occasionally, phase distance relays are used for backup.

4. Bus Protection

a. Remote Tripping

Short-circuit faults on buses can be isolated by allowing remote substation breakers on all lines that feed into the faulted bus to trip by zone 2 or time ground relay. This type of bus protection is simple and the most economical. It has the disadvantage that any loads fed by lines to the remote substations are also removed from service. Another disadvantage is that the time necessary to clear the fault may be intolerable.

b. Bus Protective Scheme

Short-circuit faults can be removed by a bus protective scheme in which all the substation breakers associated with a faulted bus are tripped. The two basic types of bus protective schemes are current differential and voltage differential. The current differential scheme connects all the current transformers on all the circuits connected to a bus in parallel, and the relays operate on the unbalanced current that exists during fault conditions. During normal conditions, there should be no unbalanced current, since the current entering a bus must equal the current leaving a bus. Restraint coils help to compensate for unequal current transformer performance during external faults, but the scheme still must be applied carefully on buses with high short circuit capabilities.

Voltage differential schemes use the same parallel connection but connect a high impedance voltage element across the parallel. It is possible to set this voltage element well above the worst case external fault voltage and still retain adequate sensitivity for internal faults. This type of relay performs well on buses with high short circuit capability.

5. Breaker Failure Protection

When system stability limits are such that remote backup (zone 3) time for clearing a fault with a failed breaker is excessive, then local backup or breaker failure relaying may be employed. This relaying employs contacts from the protective scheme to energize a timer through a breaker "a" contact or a sensitive current relay. If either the protective scheme resets or the current relay drops out within the set time, nothing happens. If the timer times out, it trips a hand reset lockout relay that in turn trips all breakers connected to the failed breaker and transfer trips the remote end breakers in the case of a ring or 1 1/2 breaker bus. Typical breaker failure timers are set from 6 to 15 cycles.

6. Distribution Lines

Four basic devices are used to detect faults and isolate faulted sections of distribution circuits. These are overcurrent relays, reclosers, fuses and sectionalizers.

a. Overcurrent Relays

Overcurrent relays will most commonly be used to control the circuit breaker at the substation. Generally, on a typical radial distribution feeder, two phase and one ground (if the system is grounded) nondirectional inverse time overcurrent relays with instantaneous elements are applied. The time current characteristic chosen will depend upon what downstream devices are present. See Figure XII-6.

b. Automatic Circuit Reclosers

Reclosers are devices similar to circuit breakers but more compact and self-contained so that they may be mounted on poles out on the distribution circuit. The controls permit various combinations of instantaneous and time delayed trips and automatic reclosures so that coordination may be accomplished with both upstream and downstream devices. Reclosers may be single phase or three phase interrupters. Single phase reclosers are series trip devices, and three phase reclosers may be either series trip or nonseries trip devices. Nonseries trip reclosers usually employ a solid state control and have a self-contained battery.

Single phase reclosers usually provide better service reliability to rural distribution circuits because a fault to ground on one phase will not trip the other phases. However, where loads are predominantly three phase, or where the load on the circuit is large, three phase reclosers with ground trip settings are desirable in order to achieve the required sensitivity for ground faults.

c. Sectionalizers

These devices are similar to reclosers, except that they do not interrupt fault current. Instead the sectionalizer counts trips of an upstream recloser and opens its contacts during a deenergized period following a predetermined number of interruptions. Sectionalizers can, however, interrupt load currents within their rating.

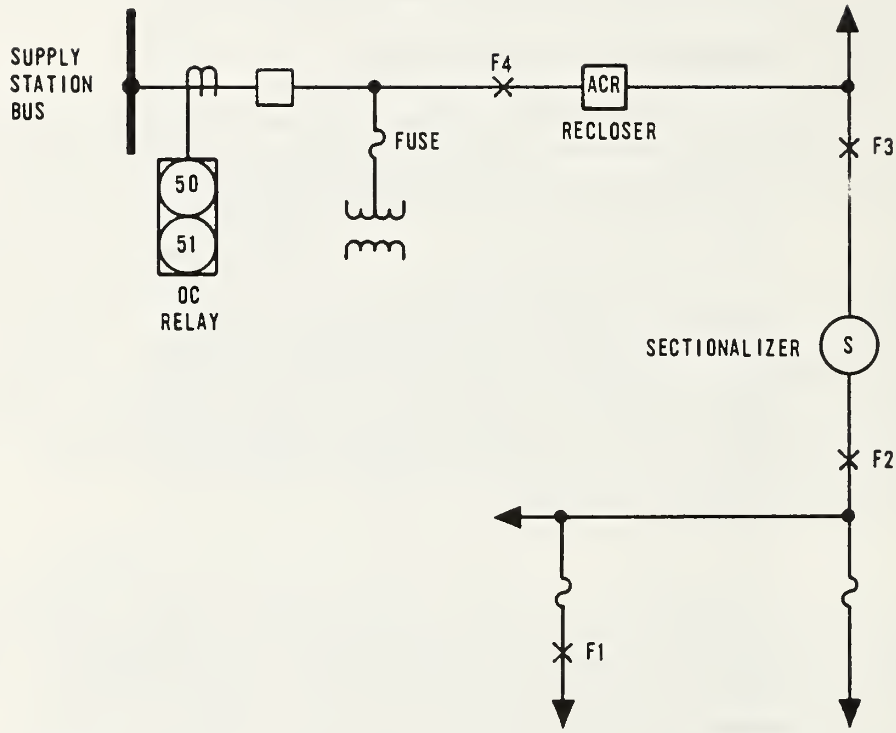


FIGURE XII-6 DISTRIBUTION CIRCUIT
PROTECTIVE ELEMENTS

d. Fuses

Fuses are used both to protect connected distribution transformers and to protect sections or branches of the distribution circuit. They are most commonly supplied in outdoor holders that are combination fuseholders and disconnect switches. Fuses are usually applied as the farthest downstream device in a sectionalizing scheme becuase of their nonrepeating nature. An upstream recloser trips and recloses several times with the accumulated "on" time being sufficient to blow the fuse during a delayed trip. The recloser then resets before the trip occurs. Fuses are also used to provide bypass protection when removing automatic circuit reclosers from service.

e. Coordination

Coordinating these devices on a distribution circuit involves the progressive disconnecting of sections of the distribution circuit beginning at the end farthest from the station until the fault is removed. Since several different types of devices are involved, this process can be more complex than coordinating a transmission line. For details of distribution system coordination principles, refer to REA Bulletin 61-2, "Guide for Making a Sectionalizing Study on Rural Electric Systems."

Referring again to Figure XII-6, it may be seen that a fault at F1 should be interrupted by the fuse. This means that the relay, recloser and sectionalizer must be programmed so that they will let enough accumulated fault current through (integrated over several reclosures) that none of these devices lock out. Generally, the recloser will have one fast and three delayed trips in such a situation. Time curves will be selected so that the fuse will blow during the second delayed trip. The sectionalizer would be programmed to open following the second delayed trip to clear a fault at F2. A fault at F3 would then be cleared when the recloser locks out following the third (delayed) trip. The relay would be set to clear a fault at F4 but coordinated with the line recloser so as not to trip for a fault at F3, paying careful attention to overtravel and reset time following each successive interruption.

This is a simplified example of distribution coordination and ignores complications, such as long branches and improperly applied protective devices, both common occurrences on real distribution systems. In such cases, compromises must be made and areas of nonselectivity accepted. The coordination process involves moving these areas of nonselectivity into positions where they do the least harm.

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CHAPTER XIII - INSTRUMENTS, TRANSDUCERS AND METERS

A. INTRODUCTION

Substations employ many different systems to monitor operation. Depending upon equipment types and configurations, a large variety of instruments, transducers, and meters may be used to perform these functions.

In this chapter various types of instruments, transducers, and meters used in substations are presented. Characteristics and construction of the devices are described and operation is discussed.

B. INSTRUMENTS AND TRANSDUCERS

1. Definitions

An instrument is a device for sensing the magnitude of a physical quantity. It is calibrated or programmed to indicate or record this magnitude based on a known standard. The instrument may be indicating or recording. A transducer is a device that converts a physical quantity to a proportional low level dc signal. Electrical transducers typically change amps, watts, volts, and vars to millivolt or milliampere signals. Transducer outputs can be used to operate local instruments or can be employed in data acquisition systems.

a. Indicating Instruments

An indicating instrument depicts the present value of the quantity measured by the position of a pointer relative to a scale or as a digital display. It is used to give an observer information regarding the present operation of equipment or circuits.

b. Recording (Graphic) Instruments

A recording or graphic instrument makes graphic records of the value of a quantity as a function of time. This type of instrument is used when a permanent record of how the measured quantity varies with time is needed.

2. Types of Instruments and Transducers

Instruments (indicating and recording) and transducers may be grouped according to the quantity they measure. The specific quantity is generally used with the suffix "meter" to identify the instrument. Thus, an ammeter is an instrument that measures amperes; a voltmeter is an instrument that measures voltages, etc. The most commonly used instruments for measurements of electrical quantities are: ammeter, voltmeter, wattmeter, varmeter, frequency meter, and ohmmeter.

3. Classification of Instruments

Instruments may be classified with respect to the method in which they are mounted. The two basic types of mountings are: switchboard (or panel) type and portable.

a. Switchboard or Panel Instruments

Switchboard instruments are intended for fixed installation on switchboards, panels or consoles. Since they are constructed for fixed installations, they require more careful handling in transport than the portable instruments. Panel instruments are similar to switchboard instruments, but are used where smaller scale instruments are satisfactory.

b. Portable Instruments

Portable instruments are used for calibration of switchboard instruments, trouble shooting, testing, and routine maintenance work. They are built for more rugged use than switchboard or panel instruments, but must, nevertheless, be handled with care.

4. Component Parts of Instruments and Transducers

a. Analog Indicating Instruments

The component parts of analog indicating instruments are: mechanism, scale, base, and cover. The mechanism is an arrangement of parts for producing and controlling the motion of the indicating hand or pointer. The mechanism for electromagnetic instruments includes the moving element, magnetic structure, control spring, and instrument hand or pointer. The component

parts of thermal instruments are the same as those for electromagnetic instruments except the mechanism consists of the moving element, bimetallic strip, heater, adjusting spring, and instrument hand or pointer.

b. Digital Indicating Instruments

These instruments are completely solid state and usually require inputs in the form of dc millivolt signals from transducers. The instruments then condition the signals to eliminate noise bursts and surges, feed the conditioned signals to analog to digital converters followed by binary to decimal encoders, and display the quantities on gaseous discharge or light-emitting diode displays. Internal "clocks" (usually 1 kHz oscillators) update the displays every millisecond.

c. Recording Instruments

The component parts of recording instruments are: mechanism, indicating scale, chart, base and cover. The mechanisms of recording instruments can be similar to that of indicating instruments, but in addition, include arrangements of parts for producing and controlling the motion of marking devices (pens or scribes), chart driving mechanisms, and chart carriages. For certain specialized recording applications, such as energy metering, magnetic tape transports may be employed.

5. Analog Instrument Scales

The instrument scale depicts the numerical value of the quantity being measured as indicated by the position of the hand or pointer with respect to scale markings. Convenient scales will give more accurate information and lessen observer eye strain. There are two basic types of instrument scales: linear scale and nonlinear scale.

a. Linear Scale

This scale is divided into a number of equally spaced segments, each segment representing the same unit of measurement. This type of scale is used when there are wide variations in the magnitude of the measured quantity.

b. Nonlinear Scale

This scale is divided into a number of unequally spaced segments. Each segment may or may not represent the same unit of measurement. Usually the segments are expanded at one end of the scale and compressed at the other end of the scale. This type of scale is used when variations of the measured quantity are small and usually fall in the expanded area of the scale permitting more accurate readings.

6. Operating Procedures

Instruments furnish valuable and indispensible information on the performance of an electric system or device. Without this information, the operator would be almost completely uninformed and would have to depend upon some crude or often inaccurate observations. Any abnormal indication should be immediately investigated.

a. Reading Instrument Scales

The best instrument will serve no purpose unless properly read and correctly interpreted. Good lighting is essential to accurate reading; glare due to reflection of concentrated light should be avoided. Newer instruments have special covers to reduce glare. Some instruments are direct reading in that the scales directly furnish the values of the measured quantities, whereas other instruments require the use of instrument constants called scale factors. In this latter case the actual measured quantity is obtained by multiplying the instrument indication as shown on the scale by the scale factor. The scale factor may be shown on the instrument or may be associated with the position of an instrument switch. In the latter case, each position of the instrument switch will represent a different scale factor. EXAMPLE: An ac ammeter with 0-5 ampere scale and 50 divisions has its indicating pointer located on the 35 division point. The scale factor is 20 as shown on the ammeter switch. The measured value is:

$$\frac{\text{Instrument Reading X Scale}}{\text{Total Divisions}} \times \text{Scale factor} = \frac{35 \times 5 \times 20}{50} = 70 \text{ amp}$$

b. <u>Care of Instruments</u>

Instruments can withstand a certain amount of abuse such as occasionally going off scale for momentary periods, but sustained overloads to the meter will damage the mechanism or pointer. Instrument covers should be tightly fastened to the case to prevent entrance of dust or fumes. Instruments should not be left for extended periods without covers.

(1) Switchboard Instruments

These instruments are rather rugged devices, but should be protected from excessive vibration and shock. The instruments should be kept clean to facilitate reading of the measured quantity.

(2) Recording Instruments

Recording instruments require additional care because of the chart drives and the recording devices. Round charts are replaced on a daily, weekly, or monthly basis depending on the instrument. This work should be done carefully to avoid any damage to the mechanism. The replacement of strip charts varies according to the length of the chart and the chart speed and should be done before the chart is expended. A recording instrument with a used-up chart will fail to record and consequently important information may be lost. Proper ink and clean inking mechanisms are the main factors in obtaining good records.

(3) Portable Instruments

The handling of portable instruments demands reasonable care. They should not be exposed to sudden jars or excessive vibration lest some of their sensitive parts such as bearings, restraining springs, etc., become damaged. When transporting portable instruments in vehicles, they should be placed on padded supports so that vibration caused by the vehicle engine or an uneven road surface will not affect the instrument mechanism. When using the instruments, they should be placed in a clean place protected from excessive dust or fumes and from hazards due to

falling objects. Instruments that are equipped with range selector switches should be first used on the highest range that will give the least pointer deflection. The range giving the best reading can then be selected.

Connection of ammeters or current coils of wattmeters into the secondaries of current transformers requires great care. Current transformer secondaries should never be open-circuited when the primaries are energized carrying load currents. When using portable wattmeters, care should be taken not to overload the current coils of the instrument. For this reason, it is always recommended that indicating ammeters be used in series with the wattmeter current coils to make sure that the current ratings of the wattmeter coils are not exceeded.

C. METERS

1. Definition

An electricity meter is a device that measures and registers the integral of an electrical quantity with respect to time. The term "meter" is also used in a general sense to designate any type of measuring device including all types of electrical measuring instruments. Use of "meter" as a suffix to a compound word (e.g. voltmeter, ammeter, frequency meter) is universally accepted. However, in this chapter the narrow meaning of "electricity meter" is used.

2. Types of Electricity Meters

The most common types of electricity meters are: watt-hour meter, var-hour meter and ampere-hour meter.

a. Watt-hour Meter

The watt-hour meter is an electricity meter that measures and registers electric energy in watt-hours or kilowatt-hours (1,000 watt-hours). EXAMPLE: If the active electric power of a circuit is 15 kw and is consumed at a uniform rate for 3 hours, the watt-hour meter will register 3 x 15 = 45 kwh.

b. Var-Hour Meter

A var-hour meter is an electricity meter that measures and registers reactive power in reactive volt-ampere-hours (or reactive kilovolt-ampere-hours).

c. Ampere-hour Meter

An ampere-hour meter is an electricity meter that registers the quantity of electricity in ampere-hours.

3. Demand Meter

A demand meter is a device that indicates or records the maximum average load over any specified time interval (usually one hour or less) or the average load over a number of equal time intervals. It is a special form of electricity meter indicating or recording the measured load for a given time interval and then resetting.

4. Combination Watt-Hour and Demand Meters

These meters measure and register load and also indicate or record maximum demand.
EXAMPLE: If the active electric power in a circuit at the beginning of the measuring period is 20 kw and is uniformly decreasing until it reaches 10 kw at the end of 1 hour and then continues at the same uniform rate of 10 kw for two more hours, the watt-hour meter will read 35 kwh at the end of the third hour and the demand meter will read a maximum 1-hour demand of 15 kw.

5. Types of Meter Indicating and Recording Devices

Each meter has a device that records the measured quantity. An electricity meter usually has a register, which registers the integrating load. The demand meter has an indicating, graphic (recording), printing, or digital device.

a. <u>Electricity Meter Registers and Register Constants</u>

The registers are the prime concern of the operators since the registers furnish the magnitude of the electrical energy consumed by the load.

(1) Register

The meter register may be dial (pointer) type or cyclometric (digital) type. In the dial type register, 4 or 5 dials are used to show the quantity measured. The register reads from left to right with the highest reading on the 4-dial register 9999 and on the 5-dial register 99999. The cyclometric register usually consists of 4 numbered rotating discs with the applicable number on each disc visible through a slot on a plate in front of the register.

(2) Register Constant

The register or dial constant of a meter is the multiplier used to convert the register reading to the actual measured value. Its value may be 1, 10, or any multiple of 10. Another constant, used with watt-hour meters, is the watt-hour constant, which is the registration of one revolution of the meter disc expressed in watt-hours. This constant is used only when calibrating watt-hour meters but can be used to calculate the register constant. The register constant is usually marked on the meter register and the watt-hour constant is shown on the meter nameplate.

b. <u>Indicating Demand Meter</u>

This meter has a sweep hand to indicate the maximum demand for any given period. This period might be 15, 30 or 60 minutes. The maximum demand indicating hand is generally reset every month when the watt-hour meter reading is obtained.

c. Recording Demand Meter

This meter records the demand for each given demand period on either a round or strip chart. This chart, therefore, indicates all the demands over a given period. The maximum demand is determined by inspection of the meter chart.

d. Contact Device

This was originally a pair of contacts on a cam geared to the rotating disc shaft of the watt-hour meter to produce a series of pulses. The pulse rate was directly proportional to the speed at which the meter disc rotated. Today, a second slotted disc geared to the meter shaft passes between a photocell and a light source. The resultant voltage pulse train produced is amplified and applied to a reed relay to produce a contact pulse output.

e. Printing Demand Meter

A printing demand meter receives the pulse train from a contact device and notches a print wheel forward one number each time a pulse is received. At the end of the demand period, the printing demand meter prints on a paper tape the number under the print mechanism and resets the wheel to zero. The tape then shows all the demand readings. The maximum demand can be obtained by inspection of the numbers printed on the tape.

f. Magnetic Tape Demand Meter

This meter records each pulse on a magnetic tape cartridge with a corresponding time base track for subsequent translation by computer.

g. Totalizer

This solid state device received pulse trains from several watt-hour meters and produces a single output pulse train proportional to the sum of the inputs. Inputs may be additive or subtractive.

h. Demand Meter Constant

The constant of a demand meter is the multiplier used to convert the indicated or recorded demand reading on the meter to actual measured values. This constant may be 1, 10, or a multiple of 10. The demand meter constant and the register constant on the watt-hour meter do not necessarily have the same value.

6. Connection of Watt-Hour and Var-Hour Meters

Watt-hour and var-hour meters must have both current and potential connections to measure the active and reactive energy. Watt-hour and var-hour meters are classified with respect to circuit connections and the type of load being measured.

a. Self-Contained Watt-Hour and Var-Hour Meters

The current and potential coils of self-contained meters are connected directly to the circuit. These meters are normally used where the circuit voltage does not exceed 240 volts and the continuous load does not exceed 30 amperes. Self-contained watt-hour meters for 200 and even 400 ampere continuous load currents and 480 volts circuit voltage are available but are usually only used in special cases.

b. Transformer-Type Meters

The current and potential coils of transformer-type meters are connected to the circuit by means of current and potential transformers. These meters are normally used when the circuit voltage exceeds 240 volts and/or the current is above 200 amperes. Current transformers are used to reduce the current to the meter to 5 amperes at rated load. Potential transformers are used to reduce the voltage to the meter to 120 volts.

c. Single-Phase Watt-Hour Meter

Both self-contained and transformer-type meters may be used for single-phase systems. These meters have only one current and one potential

coil. The transformer-type meter is usually equipped with a small indicating lamp to show when the potential coil is energized. This is important where the secondary of the potential transformer is fused.

d. Three-Phase, 2-Element Watt-Hour Meter

These meters have two current and two potential coils and are used on 3-phase, 3-wire systems. Transformer-type meters require two current transformers and two potential transformers. The meters often have two small indicating lamps to show when the two potential coils of the watt-hour meter are energized.

e. Three-Phase, 2-1/2-Element Watt-Hour Meter

These meters have three current coils and two potential coils and are used on 3-phase, 4-wire systems where the error due to voltage unbalances on the 3-phase system can be neglected. Transformer-type meters require three current transformers and two potential transformers. There are two potential indicating lamps to show when the two potential coils are energized.

f. Three-Phase, 3-Element Watt-Hour Meter

These meters have three current coils and three potential coils and are used on 3-phase, 4-wire systems where both current and voltage unbalances can be expected. Transformer-type meters require three potential transformers and three current transformers. There are three potential indicating lamps to show when the three potential coils are energized.

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CHAPTER XIV - AC & DC AUXILIARY SYSTEMS

A. GENERAL

This chapter is intended as a guide to the design of the ac and dc systems to serve substation auxiliary loads. The uses of and design requirements for each system are presented, types of systems are discussed, and the equipment used for each system is described.

B. AC AUXILIARY SYSTEM

1. Typical Loads Supplied

Substation ac auxiliary systems are typically used to supply loads such as:

a. Transformer cooling, oil pumps and load tap changer

b. Circuit breaker air compressors and control circuits

c. Outdoor device heaters

d. Outdoor lighting and receptacles

e. Control house

(1) Lighting and receptacles

(2) Heating, ventilating, air conditioning

(3) Battery charger input

(4) Water well pump

f. Motor operated disconnecting switches

2. Design Requirements

The following must be determined to design the ac auxiliary system:

a. Demand Load

The connected kVA of all substation ac loads should be tabulated and a demand factor applied to each. Demand kVA is used to size the auxiliary transformer(s). Load diversity and load factor need not be considered in this case.

In auxiliary transformer sizing, substation growth rate should be examined. If expansion is planned in the near future, the estimated demand load of the expansion should be considered in the transformer size. If expansion is in the far future, it may be economically advantageous to plan for the addition of a transformer at expansion time.

b. Number of Primary Feeds

In small distribution substations the use of dual auxiliary feeds with a transfer scheme is usually unnecessary.

As substation size increases, customer load criticality increases. The Borrower, with his Engineer, must make the decision as to redundancy of substation auxiliary services in light of economics and customer requirements. Large transmission substations, servicing large load blocks, and distribution stations, should have dual feeders serving two separate auxiliary transformers.

When dual feeds are selected, two separate, independant sources should be located so the loss of one will not affect service of the other. The least reliable should be designated alternate supply. The Borrower and his Engineer may consider, as a normal source, a tertiary winding of the power transformer.

An alternate source could be a distribution feeder at a customer service level, 480 or 240 volts, single or three phase. Depending on auxiliary secondary voltage level selected, this could eliminate one transformer.

c. Overhead or Underground Entry

The auxiliary source(s) could be either overhead or underground distribution lines. When undergrounding within the substation property, even from an overhead

source, direct buried conduit is feasible. A spare, capped, conduit should be installed to minimize down time if a cable failure occurs. The faulted cable can always be removed after service restoration.

d. Critical Loads

Some substation loads must be maintained. These include:

(1) Battery chargers which, through the batteries, supply breaker trip and dc communication circuits.

(2) Transformer cooling

(3) Low voltage ac circuits to power circuit breakers.

(4) Trouble light receptacles in the station yard.

(5) Security lighting

(6) Breaker control circuits

(7) Fire alarm circuit(s)

(8) Electric heating

Critical loads for each station should be determined. These loads should be served from a panel(s) fed from the normal source and representing the minimum load for transfer to alternate supply.

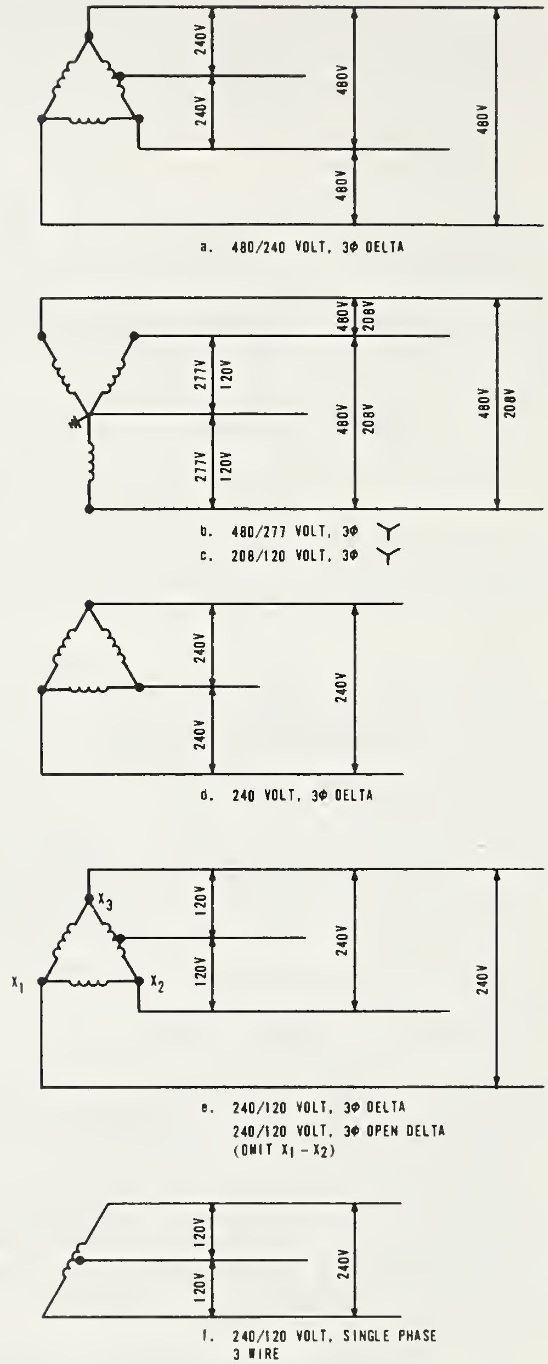
e. Secondary Voltage Level

Several secondary voltage or utilization levels are available for ac auxiliaries. For the purposes of standardization, on a given power system, it is best that only one level be selected. This is not a limiting rule however. Exception could be justified.

Possible secondary voltage levels as illustrated in Figure XIV - 1 are:

(1) 480/277 Volts, Wye Connected, Three Phase, Four Wire

Three phase transformer fans and oils pumps need to be specified at 480 volts. In practice the



NOTE: A 0° OR 30° PRI. TO SEC. ANGULAR DISPLACEMENT MAY EXIST DEPENDING ON PRIMARY CIRCUIT (Δ OR Y)

FIGURE XIV-1

TYPICAL A.C. AUXILIARY SYSTEM SECONDARY VOLTAGES

motors are rated 460/230 volts but this is inside the NEMA + 10 percent voltage requirement.

The advantage here is luminaires can be equipped with 277 volt ballasts saving lighting transformer costs over use of more common 120 volt lamped luminaires. Convenience receptacles are fed through small dry type 480-120 volt transformers.

(2) 208/120 Volts, Wye Connected, Three Phase, Four Wire

Three phase 208 volt or single phase 120 volt or a combination of the two can be used for transformer cooling. Combination power and lighting panels can be used resulting in reduced labor and material costs. This savings could be offset by higher conductor costs as compared to the 480 volt system. Receptacles can be served with 120 volts directly.

(3) 240/120 Volts, Delta Connected, Three Phase, Four Wire

This is the most common level in use in moderate size substations. One phase of the auxiliary transformer is center tapped to obtain 120 volts. Combination panels can be used and 240 volt single phase loads can be served.

(4) 240/120 Volts, Open Delta Connected, Three Phase, Four Wire

This is essentially the same as the closed delta connection except only 58 percent of the kVA capacity of the three transformers can be used. This configuration will provide construction economy for a medium size installation or for temporary use. With single phase units, the third transformer can be added in the future for increased kVA capacity. It is frequently used for construction power where both three phase and single phase supplies are required.

(5) 240/120 Volts, Single Phase, Three Wire

This is "Residential" service but applicable to small substations. Common panels can be used, with two available voltages.

f. Transfer Scheme

Where two sources, normal and alternate, are feeding substation auxiliaries a means to transfer from one to the other must be established. At an attended station this can be a manual transfer arrangement. Automatic transfer must be provided at an unattended station. Transfer is done on the secondary side for equipment economy. Article 700 of the National Electrical Code (N.E.C.) outlines general requirements for this type of scheme. A typical configuration is shown in Figure XIV-2.

Transfer switch selection is an important factor in the system design. Operation should be break before make double throw operation to prevent shorting the two sources. Mechanical interlocking should be provided to ensure the switch can be in only one of the two positions. The switch should have an ampere withstand capability for faults at points A, B and C, Figure XIV-2. The fault at "C" will be highest, the feeder impedence to "B" and "A" limiting the fault current to an amount below that at "C".

The auxiliary system in Figure XIV-2 assumes transfer of all loads. The full load current of the 150 kVA transformer is 360 amperes so a 400 ampere switch would be selected.

Assuming a 250,000 kVA source, 2-500 kcmil, 3.05 meter (10 foot) long feeders per phase to the switch, and 4 percent transformer reactance, the fault current is approximately 10,000 amperes. This value is well within manufacturer's standard ratings for 400 ampere full load transfer switches.

Automatic transfer switches are built to detect emergency conditions and transfer to the alternate supply when the normal supply falls to 83 percent of rated voltage. Return to normal supply is accomplished through an adjustable time delay at approximately 92-95 percent of rated voltage. A variety of accessories are available with transfer switches. Manufacturer's data is readily available and the Engineer should consult such data in specifying a transfer switch. Means should be provided to alarm for loss of voltage from either source.

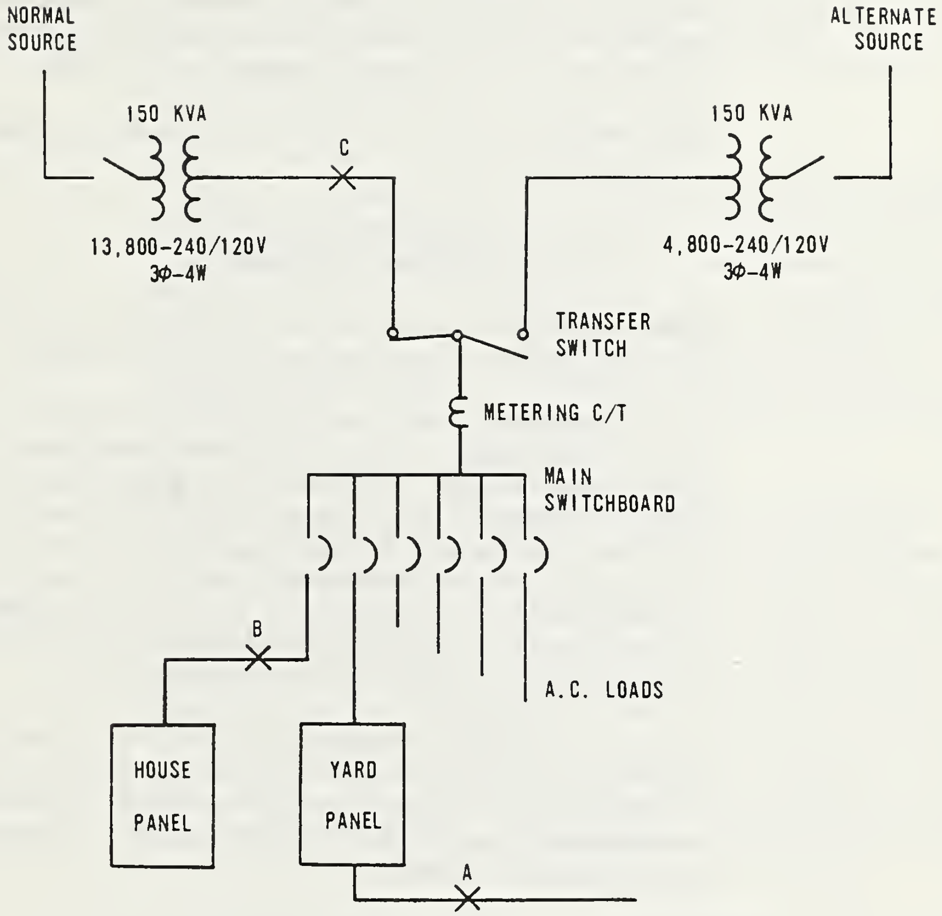


FIGURE XIV-2
TYPICAL AC AUXILIARY SYSTEM

g. Auxiliary System Fault Currents

The determination of fault currents in 3 phase ac auxiliary systems is just as basic as the determination of load currents in sizing circuit breakers or fuses. The protective device must operate or open during faults as well as carry load current during normal conditions or equipment damage could result.

The symmetrical short circuit (fault) current is computed by:

$$I_F = \frac{\text{Line to Line kv}}{\sqrt{3}\ \text{Ohms Reactance}} \qquad \text{XIV-1}$$

Ohms reactance is the total reactance of all current carrying parts from the source to the fault.

In Figure XIV-2 the 250,000 kVA source has a reactance of 0.00023 ohms. The transformer reactance is 0.0023 ohms, the current transformer 0.0005 ohms, the 3.05 meter (10 feet) cable about 0.001 ohms and so forth. All reactances are totaled and used in the above relation. The asymmetrical fault current is a function of the fault circuit X/R ratio. A multiplying factor (1.7) for the asymmetrical current is satisfactory for auxiliary power system calculations.

Fuse and circuit breaker manufacturers have handbooks with X, R, and Z values for transformers, current transformers, cables, etc., together with methods for determining protective device ratings based on estimated fault currents.

3. Equipment

a. Transformers

The main item of equipment in the ac auxiliary system is the transformer. R.E.A. Specification U-5 covers pad mounted transformers from 75-500 kVA, single and three phase. This type of transformer is good for large substation auxiliary service use. The increasing use of undergrounding has made these units readily available from major manufacturers. Pad mounts meeting R.E.A. specifications and with R.E.A. accessory packages are catalog items.

The secondary voltage levels listed in Section B.2.e are manufacturers' standards.

The Engineer should consider the feasibility of establishing substation auxiliary system voltage at the same level as that for serving underground customers. With this standardization, spare transformers can be stocked and both customer and substation service maintained at minimum cost.

R.E.A. Bulletin 161-22, "Application Guide for Transformers" is applicable for selection of ac auxiliary system pad mounted transformers. Such units can be purchased with fused switches on the primary side for transformer fault current protection. High voltage fuses, in this use, sized for full load transformer primary currents will inherently have sufficient current interrupting ratings to protect the transformers under fault conditions. Primary load break switches are also available.

If the normal and alternate sources are overhead, pole mounted, hook stick operated, fused switches are a possible solution to transformer primary protection. From the switches, the transformer feeders are undergrounded to the pad. Cable for this application is covered by R.E.A. Bulletin 61-15, "Selection and Application of Underground Rural Distribution Cable."

Pad mounted transformers and the kVA ratings previously mentioned apply to a fairly large substation. For smaller installations structure mounted distribution transformers, properly applied, can be used.

b. Electrical Panelboards

The definition of a branch circuit panelboard in the N.E.C. (Article 384) is one having more than 10 percent of its overcurrent devices rated 30 amperes or less for which neutral connections are provided. Additionally, the number of branch circuit devices in one enclosure is limited to 42 poles.

Switchboards differ from panelboards in that the former are free standing. Front or rear access to line and load terminals are vendor options. Branches can be group mounted or individually mounted, with or without barriers.

Enclosures should be specified NEMA 1, general service, or NEMA 3R, raintight for outdoor use.

Panelboards are available for flush or surface mounting, with fusible or circuit breaker branch circuits. Main breakers, if required, can be furnished. Voltage ratings for any selected level from Section B.1.e can be supplied.

The main decision to be made in panelboard selection is whether to use fusible or circuit breaker branches. The branch circuit device is used to protect the branch circuit wiring so the decision should be based on first cost and maintainability. For a very small installation with few circuits, fuses will mean lower first cost.

If fuses are selected, an inventory must be maintained at the substation. There is always the possibility, however remote, that the wrong size could be used as replacement for a blown fuse. These problems do not exist with circuit breakers, a plus factor relative to maintainability.

For lighting circuit service exclusively, in a moderately sized installation, a circuit breaker panelboard offers the advantage of switching the lights thereby eliminating light switches. For exterior lighting, the Engineer may consider mounting a weatherproof three pole magnetic contactor fed from an adjacent outdoor panel. Three branch circuits of lighting can be handled by the contactor. Only three wires are required between the Contractor and the control house where a two station momentary contact push button station is installed.

c. <u>Lighting and Heating Equipment</u>

Outdoor lighting serves two basic purposes, substation security and safety. Depending on the area, certain luminaires may be used during hours of darkness for substation security. These are photo-electrically controlled. A microwave tower could require F.A.A. lighting. This would also be controlled photo-electrically.

It should be determined, for a given R.E.A. system, if security lighting is required. Is it sometimes

better not to call attention to the location, possibly preventing malicious vandalism?

Lamps for outdoor use are essentially incandescent, mercury or sodium lamps. Except for an unusual condition, the lamps presently in use on a given system, should continue in use, simplifying inventory. The unusual condition could be a new large substation where a different source is desirable and a separate, on station inventory can be kept.

Luminaires for substation use, from the basic flat dome reflector to Illuminating Engineering Society (I.E.S.) pattern refractors, are available. Pole top or bracket mountings can be used. The Engineer, with the proper vendor data can develop a lighting layout to satisfy the purpose required. Yard lighting design is beyond the scope of this guide. The basic requirements are one or two foot candles in equipment areas. Convenience receptacles should be in equipment cabinets and also stategically spotted to serve 50 ft. extension cords with trouble lights. Convenience receptacles in the substation yard should have ground fault interruption protection.

Indoor lighting should be designed for maximum operator convenience. Luminaires should be located to adequately illuminate relay and control panel fronts. With fluorescent units, four foot lamps are recommended, storage being easier than for eight foot lamps. Duplex receptacles should be provided for extension cord lights for initial panel interconnection work, relay setting and plant maintenance.

Control house electric heating should be provided for comfort and freeze prevention. This can be done with ceiling or wall mounted electric unit heaters and/or electric base board heating units. Powered roof ventilator(s) should be provided along with floor level, manually operated wall louver(s) to provide for three to five air changes per hour. Louvers should be provided with fusible links as a means, in case of fire, to keep damage to a minimum. Gravity roof ventilators should always be installed to prevent concentration of hydrogen in battery rooms.

Air conditioning of the control house, where required, is best provided by packaged, through wall unit(s).

These required no plumbing connections. Built-in resistance heaters are provided on some units to provide all season use. Vendor data is available as an aid in selecting such units.

4. Summary

A substation ac auxiliary system consists mainly of the following parts:

a. One or two incoming primary feed(s) seldom above the 15 kV level, one designated normal source, the other designated alternate source. The sources should be as independent as possible.

b. One or two auxiliary transformers to reduce the primary voltage to the utilization level.

c. A main switchboard, usually located outdoors between the two transformers. This switchboard houses the transfer switch and fuses or circuit breakers to feed both control house and yard panelboards.

Panelboards (indoor or outdoor) having circuit breakers or fuses sized for the loads involved with approximately 20 percent spare. If the contactor lighting scheme is selected, the contactor can be factory installed within a panelboard.

All branch circuit breakers feeding ac yard circuits shall be Ground Fault Interrupting type (G.F.I.). Where fused panels are selected, yard receptacles shall be G.F.I. type.

C. DC AUXILIARY SYSTEM

1. Typical Loads Supplied

Substation dc auxiliary systems are typically used to supply loads consisting of:

a. Relaying, supervisory, alarm, and control equipment

b. Emergency control house lighting

c. Circuit breaker operating circuits

2. Design Requirements

A substation dc system consists of a battery of suitable voltage (number of cells) and suitable size (ampere hour capacity) connected in parallel with a control bus together with properly selected voltage regulated charging equipment.

At a single location where two distinct dc voltages are required, i.e. possibly 48 volts for microwave and 120 volts for substation operation, two separate batteries and chargers shall be specified. Tapping a larger unit to obtain the smaller voltage is not recommended.

The charging equipment consists of a full wave rectifier with regulated output voltage. Normally, the charger operates continuously to furnish direct current to the control bus for steady loads such as indicating lamps, holding coils, relays plus a small current to maintain the battery at full charge. Intermittent loads of short duration such as tripping or closing of circuit breakers or automatic operation of other equipment are handled by the charger within the limits of its capacity. Any excess load is handled by the battery which is automatically recharged when the intermittent load ceases. Should the ac input to the charger fail, the battery carries the entire load.

The control bus may be a dc bus in a switchgear assembly or, in the case of a large substation, a dc or group of dc panels.

DC voltage requirements for solid state relaying, events recorders, data aquisition and other such devices are generally below the voltage levels for circuit breaker trip coils. Actual requirements vary with different vendors. Some types of equipment are provided with individual rectifiers, rack mounted, changing 120 volts, 60 hertz ac to 12, 24 or 48 volts dc. If the ac supply fails, static switching changes the source to the main dc batteries and required dc converter. An alarm indication is provided to indicate this status. Other equipment is designed to be fed directly from the main batteries with dc/dc converters to supply the static device voltage.

Two of the most important components of a substation dc system are the main battery and charger. These components should be sized correctly. Undersizing could possibly mean a circuit breaker reclose failure and undue service

interruption. Oversizing, while not damaging, is expensive. However, the cost of the supply is a fraction of total substation cost and the economics should be balanced with reliability. At a minimum, the main battery should be sized to allow normal substation operation for a number of hours.

3. Types of Cells

Before determining the cell ampere hour rating, the type of cell for the particular application must be selected. There is no need for cell standardization on a power system. Once a battery is installed for stationary service it stays in place for up to 30 years. Interchangeability on the system is unnecessary. The types of secondary cells readily available today are:

a. Lead acid

b. Nickle Cadmium (NI-CAD)

c. Lead Calcium

A brief description of the three predominant types follows. For theory and history too lengthy to be considered here, the Engineer is referred to "Batteries and Energy Systems" by Dr. C.L. Mantell, published by the McGraw Hill Book Company.

a. Lead Acid Cell

This cell has a positive plate of lead peroxide and a negative plate of pure sponge lead. The electrolyte is dilute sulphic acid. Open circuit voltage of a fully charged cell is a nominal 2.1 volts, varying from 2.06 to 2.14 volts depending on electrolyte strength and cell temperature.

Battery condition can be determined with a hydrometer where:

$$\text{Cell Volts} = \text{S. G.} + 0.84 \qquad \text{XIV-2}$$

S. G. is the specific gravity of the electrolyte. The specific gravity of the electrolyte varies with cell temperature so a thermometer should be a part of the maintenance kit. The higher the temperature, the lower the specific gravity. Battery ratings are

usually specified at 25°C (77°F). Temperature correction curves are included with the battery manufacturer's instruction manual as are charge and discharge curves.

b. Nickel Cadmium

This cell has a positive plate of nickel hydrate and a negative plate of cadmium sponge. The electrolyte is a solution of potassium hydroxide with a specific gravity of from 1.160 to 1.190 at 25°C (77°F). Open circuit voltage may vary from 1.30 to 1.38 volts. The cell voltage is 1.4 volts, fully charged at 25°C (77°F). The specific gravity of the electrolyte is constant regardless of charge state.

The nickel cadmium battery has the advantages of infrequent maintenance requirements, absence of corrosive fumes, immunity to inadvertent overcharge, and the reduced derating required for ambient temperatures below 25°C (77°F). The absence of corrosive sulphuric acid fumes allows the installation of "NI-CADS" in cubicles, a possible advantage in some installations. The primery reason for the lack of greater use of "NI-CADS" for main substation batteries is initial cost.

c. Lead Calcium

This cell is similar to the lead acid type with the exception of the addition of approximately 0.8 percent calcium to the lead grid for additional strength. This alloy also greatly reduces cell internal losses.

In the case where no standards are established, the Engineer should select battery type based on:

(1) First cost

(2) Years of float life

(3) Annual depreciation

4. Typical Loads and Duty Cycle

To accurately specify a battery and associated charger, the dc load must be accurately defined. Each single item of equipment connected to the dc system must be individually tabulated with the following pertinent data included:

Voltage

Current requirement

Duration of operation

Frequency of use

The last two items constitute the duty cycle.

DC voltages of 24, 32, 48, 120 and 240 are normally encountered in substation design. For the purpose of this guide, a 120 volt battery with a nominal voltage per cell of two volts and 60 cells will be considered. A final voltage of 1.75 per cell or 105 volts for the battery will complete our model.

DC system loads consist of both continuous and intermittent loads. Continuous load involves the battery three to eight hour ratings. It consists of indicating lights, relays and any other equipment continually drawing current from the dc bus. Emergency lighting consisting of circuits energized during an ac outage plus certain communication circuits also involves the one to three hour rating.

Intermittent or momentary load, constituting breaker operation, involves the one minute battery rating. The time duration for breaker operation may be only a few cycles but the battery voltage drop will be essentially the same after one minute. Breaker closing or tripping current should be used, whichever is larger. If two or more breakers are to operate simultaneously, the total current determines the one minute rating.

The sizing of dc cables and cabinets is done in the same manner as for ac services. The only exception is no demand factor should be applied to connected loads. Voltage drop should be held to within 3 percent. Special consideration relative to short circuit capacity is not a factor in a dc auxiliary system.

Figure XIV-3 illustrates a typical dc system for substation auxiliary services.

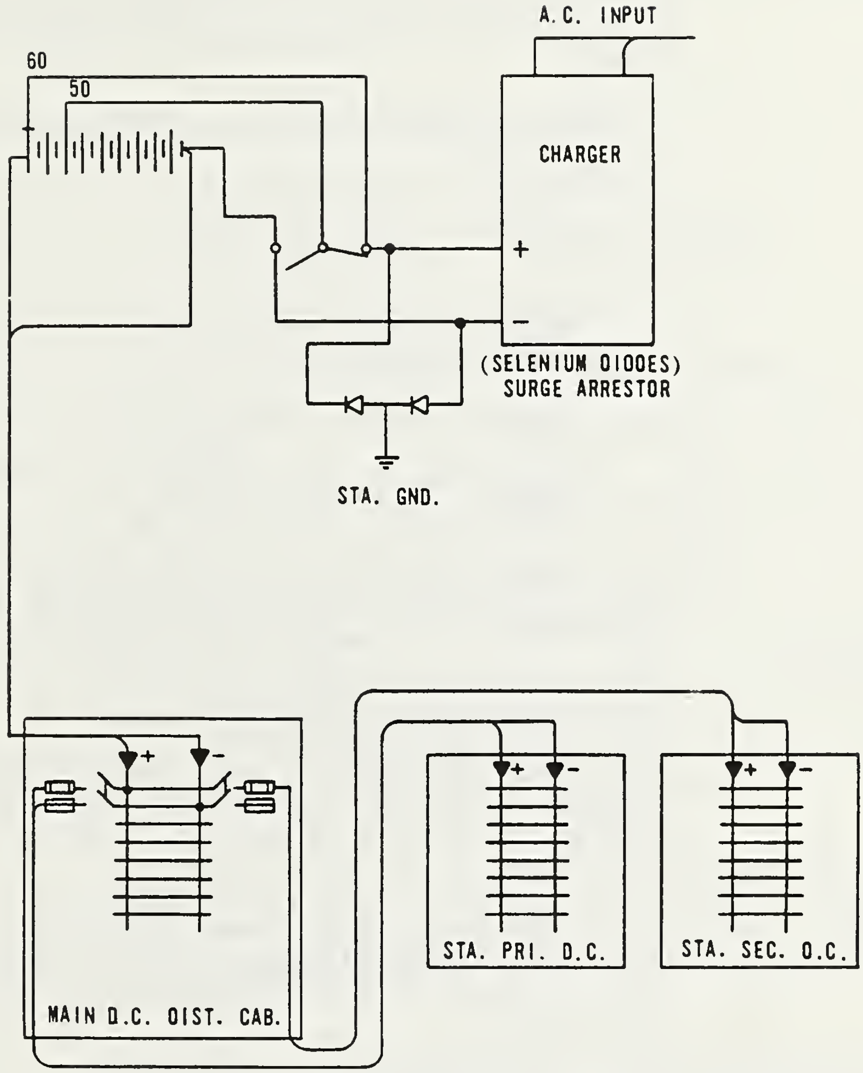


FIGURE XIV-3
TYPICAL DC AUXILIARY SYSTEM

5. Equipment

a. Battery Selection

Lead batteries are rated in ampere hour capacity at an eight hour rate to 1.75 volts average at 25°C (77°F).

The model duty cycle for a selection example could be:

10-40 Watt, 120 Volt Lamps - 3 hrs.	3.5 amperes
Relays and Panel Indicating lamps - 8 hrs.	5.0 amperes
Communications - 3 hrs.	5.0 amperes
3-Simultaneous Brkr. Operations - 1 min.	100.0 amperes

From vendor data a cell of 7 plates will furnish approximately 200 amperes for one minute to 1.75 final volts. The ampere hour capacity of the selected unit at the 8, 5, 3 and 1 hour rates is about 145, 130, 115, and 80 respectively.

This model duty cycle is only to serve as a numerical example of battery selection. For the 120 volt system, 60 of the lead calcium cells would be connected in series.

Quite obviously, vendor data is necessary to specify a battery. An excellent battery and charger booklet is available from C & D Batteries, Division of Eltra Corporation.

b. Charger Selection

Satisfactory battery life and service are more dependent on the design and specification of the charging equipment than on any other external factor. The most costly and complicated charger is not necessarily the best selection. Shunt wound dc generators were used for years for charging batteries but frequent adjustment was required and recharge capability was slow. For substation service, bridge rectifiers are

used. Tube type are still in service but new installations are being specified with solid state devices.

The ampere capacity of the charger can be determined from:

$$A = L + \frac{1.1C}{H} \qquad \text{XIV-3}$$

Where A = Charge capacity (amperes)

L = Continuous load (amperes)

C = Discharge (amperes hours)

H = Recharge time (hours)

Using the same model as for battery selection we have

DC Lights	3.5 Amperes-3 hrs.	10.5 AH
Communications	5.0 Amperes-3 hrs.	15.0 AH
Breaker Operations	100.0 Amperes-1 min.	1.7 AH
Panel Load	5.0 Amperes-8 hrs.	40.0 AH
		67.2 AH

Substituting in equation XIV-3 with an 8 hour recharge:

$$A = 5 + \frac{1.1(67.2)}{8} = 14.24 \text{ amperes}$$

The next largest standard size charger should be selected. If the charger is to be operated above 1000 meters (3,300 feet) altitude and above 40°C (104°F) ambient, vendor data should be checked for correction factors.

The model illustrated here is only to demonstrate a method for battery selection. Substation expansion should also be considered in initial battery/charger selection.

Single phase and three phase ac inputs at standard voltages are available. Chargers are commercially available with standard and optional devices to indicate status and to alarm unusual situations,

mainly ac failure. The Engineer should refer to vendor data to determine the required devices pertinent to the particular situation under consideration. If the selected charger uses a cord, cap and receptacle for ac supply a locking cap and receptacle should be specified.

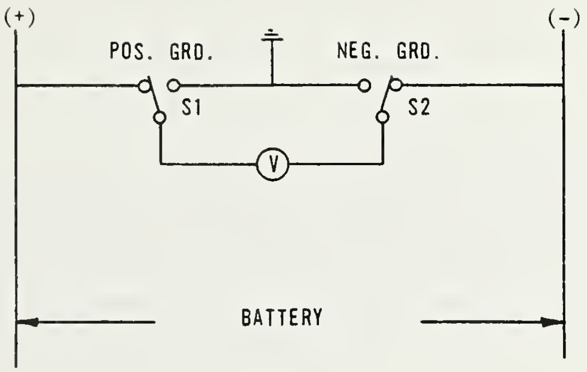
c. <u>DC Panels and Wiring</u>

The substation dc auxiliary system should be an ungrounded system. Fusible panels should be used for dc service.

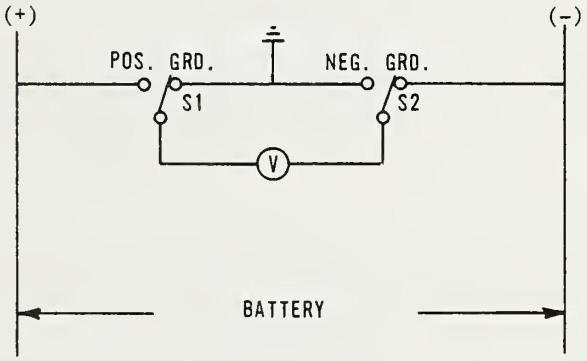
The positive leg of a branch shall be fused, the negative leg equipped with a solid link. This provides visible, protection for detecting system grounds. A ground detection method as part of the charger using a ground detection switched voltmeter should be specified. Figure XIV-4 is a simplified diagram of such a method.

It is recommended that the positive and negative legs of the dc system be run in separate conduits and be assigned separate tray compartments where trays are used.

Relay panels having solid state equipment cannot sustain voltages higher than 140 volts dc without possible relay damage. When the battery is being recharged or equalized the dc terminal voltage could be in excess of 140 volts. In this case a 50/60 cell switch should be installed and the recharging done at the 50 cell position. Additionally, circuit breaker operation can cause transient voltage spikes which could possibly damage equipment connected to the dc bus. A surge rectifier should be installed across the battery to drain the surge energy to ground. These features are usually not available from battery charger manufacturers so it is recommended that they be installed in the battery room on a wall mounted wood panel. Figure XIV-3 illustrates a simplified diagram of a dc system with these features.



IN THE NORMAL POSITION SWITCH 1 AND 2 ARE AS SHOWN AND THE VOLTMETER READS THE FULL BATTERY VOLTAGE. TO CHECK FOR A GROUND ON THE POSITIVE LEG SWITCH NUMBER 1 SHOULD BE TURNED TO THE ALTERNATE POSITION AS SHOWN.



THE VOLTMETER WILL THEN READ O VOLTS IF THERE IS NO GROUND ON THE POSITIVE LEG. IF THERE WERE A GROUND THE VOLTMETER WOULD AGAIN READ FULL VOLTAGE.

FIGURE XIV-4
TYPICAL BATTERY GROUND DETECTION SYSTEM

CHAPTER XV - CONTROL HOUSES

A. INTRODUCTION

As substations increase in voltage, size and complexity, the necessity for supplemental equipment such as relays, meters, controls, batteries, communications equipment and low voltage distribution equipment also increases. For small distribution substations, this equipment can usually be contained in weatherproof enclosures or control cabinets. For larger substations, separate equipment housing is necessary.

A control house provides a weatherproof and, if required, environmentally controlled enclosure for supplemental substation equipment. Additional space can be provided for workshops, equipment testing and repair, storage areas and lavatory facilities.

B. CONTROL HOUSE CONSTRUCTION

This section discusses general aspects of the control house construction. It does not attempt to cover all details of construction. REA BULLETIN 86-4 (ELECTRIC) "Presentation of Building Plans and Specifications" presents details that will apply and should be consulted.

1. Foundation

The control house foundation typically consists of a spread footing with either masonry blocks or cast-in-place walls. The footing is designed for an allowable bearing capacity based on soil data. If soil data are not available, a maximum bearing of 48 kPa (1000 lb/ft^2) can be used. The footings are installed below frost depth and in accordance with local building codes and practices.

Damp proofing of foundation walls is desirable, especially if concrete block is used. If a basement level is constructed, damp proofing should be provided. Footing drains are usually provided when a basement level is constructed.

All foundation walls should be insulated with a 5.1 cm (2 in.) thickness of rigid insulation for energy conservation. It is preferable to install the insulation on the inside of the walls, although the outside is acceptable.

2. Floor

The control house floor is typically a floating concrete slab 12.7 to 15.2 cm (5 to 6 in.) thick reinforced with welded wire fabric, deformed steel bars, or a combination of both. The finished floor elevation is usually 10.2 to 20.3 cm (4 to 8 in.) above the finished grade outside the control house.

The base beneath the floor slab should be 10.2 cm (4 in.) of compacted sand or gravel or thoroughly mixed and compacted sand or gravel or thoroughly mixed and compacted natural soil. A 0.15 mm (0.006 in.) thick plastic film vapor barrier should be installed between the floor slab and the base.

The method for cable routing in the control house must be considered before finalization of the floor slab design. Cable trenches can be formed into the floor slab or false floors can be installed providing access to large areas below the finished floor.

3. Superstructure

The control house superstructure should be constructed from fire resistant, low maintenance building materials. Most control houses presently being designed and constructed are of the pre-engineered metal or masonry block type.

The pre-engineered metal building is the easiest to procure and erect. If the manufacturer is given building size and any special requirements such as additional roof loads for suspended cable trays or other equipment, he can design and fabricate the required building components.

Masonry buildings constructed of block masonry are most economical when masonry module dimensions are used to size the building and the building openings.

Decorative block can be used as an inexpensive method to improve the external appearance. Block cores should be filled with vermiculite or equivalent insulation.

Two types of roof systems are commonly used for masonry buildings: (1) precast, prestressed concrete panels; and (2) steel joists and steel decks. A sloping roof is recommended for both systems and can be obtained by pitching the roof deck or installing tapered roof insulation. The

roof membrane must be compatible with the slope. For the slopes of 8.3 cm/m (1 in./ft) and less, built-up pitch and slab is commonly used. For greater slopes, gravel is used.

The control house should be equipped with at least one double door conveniently located to facilitate equipment entry and removal. The doors should include locking devices, astragals and adequate weatherstripping and hardware to permit a rapid exit from the control house.

Windows can be provided, if desired, in office and lavatory areas. Battery rooms and control and metering areas do not need windows although adequate ventilation must be provided.

Adequate methods for building insulation should be considered. These methods include use of insulated wall panels, ceiling insulation, storm doors and windows, and weatherstripping around all openings.

Metal buildings are shop painted and require only minor field touch-up after erection. Masonry buildings may be left unpainted or may be painted with portland cement or latex paint. All prime coats should be tinted to match the finished coat.

C. CONTROL HOUSE LAYOUT

1. Control and Relay Panels

Most relaying, metering, and control equipment is mounted on fabricated control and relay panels installed within the control house. A variety of panel types is available to suit individual requirements.

Single vertical panels can be used, particularly for distribution circuits where space requirements are minimal. The relaying, metering and control equipment can all be mounted on one panel, allocating a separate panel for each circuit. In some instances, two circuits may share the same panel.

Double or duplex panels are commonly used for higher voltage circuits necessitating additional space for equipment mounting. Normally, these panels are arranged in two parallel rows, the panel backs facing each other. In this configuration, operating, instrumentation and control equipment for a circuit is installed on the front of one

panel, and the corresponding relaying equipment for the same circuit is installed on the front of the panel directly to the rear. In some instances, two circuits may share the same control and relaying panels.

Some equipment such as static relaying systems and communications equipment is available mounted in racks. Consequently, separate relay and/or control panels are not required for this equipment.

To facilitate operation, panels are located in an arrangement that conforms as closely as possible to the actual equipment and circuit layout in the substation yard. To assist in circuit location and operation, mimic buses are sometimes used on the control panels, particularly for large complex substations. The mimic buses identify the bus and circuit arrangements. When practical, meters should be positioned at eye level and switches at a convenient operating level. Recording meters should be located for ease of viewing and chart replacement. Relays should be located beginning at the tops of the relay panels and working downward. Ample space for relay installation, removal, operation and testing must be provided.

Panel construction can include removal front plates for device mounting. In this way, only a new predrilled plate is required when changing out a device or modifying the configuration. Cutting, drilling or covering openings in the panels is eliminated.

Panel wiring is accomplished on the back sides. Devices are interconnected and wired to terminal blocks, as required, for operation and connection to devices on other panels. Panels can include small sections perpendicular to the main section at each end for installation of terminal blocks, fuse blocks, or small auxiliary devices. Cable connections from the equipment in the substation yard can be made directly to terminal blocks mounted on the panels or can be made to stragetically placed terminal cabinets. Interconnections between the terminal cabinets and the panels can then be made with single conductor wire.

Panels should be anchored to the floor in such a manner to facilitate relocation to coincide with yard equipment and circuit relocations.

Panel arrangement in the control house should permit ready accesibility to the backs of the panels.

2. DC Equipment

Substation dc equipment located in the control house normally consists of the battery, battery charger, monitoring and control devices and distribution panelboard. The battery should be located in a separate room where practical. The battery charger, monitoring and control devices, and distribution panelboard are normally located in the control and relay room to facilitate cable routing and equipment maintenance.

Detailed design requirements and procedures for the substation dc system can be found in Chapter XIV.

3. AC Equipment

A low voltage ac system is provided in the substation for lighting, convenience outlets, heating, ventilating and air conditioning (HVAC) equipment, and miscellaneus control functions.

Convenience outlets should be strategically located throughout the control house to provide adequate accessibility. The workshop and testing area should be provided with a high capacity ac source and a three phase source.

An ac distribution panelboard located inside the control house is used to supply the indoor lights, convenience outlets, HVAC equipment and other devices.

Chapter XIV contains additional information concerning design of the substation ac system.

4. Cableways

Cable routing can be accomplished by using any of the several methods. Details of these methods are covered in the following discussion:

a. Cable Trenches

Cable trenches are formed into the concrete floor slab and are covered with metal plates. The covers should be flush with the finished floor when in place. The sizes and locations of the cable trenches are based on the quantities of cables and locations of panels and equipment to be interconnected. Usually,

a cable trench is located adjacent to the backs of the control and relay panels to facilitate panel interconnections. With duplex panels, it may be desireable to utilize the entire space between the front and rear panels as cable trench, depending on circuit quantities.

b. False Floors

False floors are useful when large open areas are desirable for cable routing. The lightweight removable floor panels installed on adjustable pedestals are positioned in areas requiring extensive cable interconnections or where future plans dictate a large amount of cable rerouting. The top of the removable panels should be flush with the finished floor.

c. Conduits

Conduits can be used for cable routing in floors or along walls and for cable entrance into the control house.

Conduits are available in plastic, aluminum, heavy walled steel and thin walled steel. Each of these types may be used in control houses for wire containment to convenience outlets, lighting fixtures and other control house auxiliary power equipment.

Plastic conduit is easily installed and is available in a variety of sizes. Adequate physical and thermal precautions should be taken, when using plastic conduit, to ensure safe operation.

Metallic conduits of aluminum and steel are widely used as control house cableways. Heavy walled steel conduit provides excellent physical protection. The installed costs, however, may be relatively high because of the extensive labor required for installation. The installed cost of rigid aluminum conduit may be somewhat less than that for steel. A lower installed cost may be realized by using thin wall steel conduit, since it is less expensive and easier to install.

d. Wireways

Wireways are sheet-metal troughs utilized for routing groups of power circuits around a control house to feed various branch circuits. Conduit is used between the wireway and the devices.

Wireway offers the advantage of laying rather than pulling the cable into position and the ability to change or reroute circuits easily. Wireway is available with hinged or removable covers in a variety of lengths and sizes. Wireway should be selected and installed in accordance with the National Electrical Code.

e. Cable Trays

Cable trays can be used for overhead routing of cables to and between control and relay panels. Expanded metal or ladder type trays provide the best facilities for conductors entering and leaving the trays. An advantage of cable trays is the ability to lay rather than pull in the conductors. Suspended cable trays, however, prevent extensive use of this technique because of support locations. A large variety of types, sizes and fittings is available to suit individual requirements. Cable tray should be selected and installed in accordance with the National Electrical Code.

5. Cable Entrance

Control and power cables are brought into the control house through windows, sleeves or cable pits. The windows are square or rectangular openings, usually through the foundation wall but possibly above grade. The window openings enable many cables to be pulled without interference. To protect the cables during pulling, the windows should have smooth surfaces and beveled or rounded edges. After cable pulling, split sleeves can be installed around the cables and grouted into place. Occasionally, the windows are left open to facilitate future cable installation. Heat loss through these openings should be considered. Additional windows should be provided for installation of future cables. The windows can be constructed and bricked up to be opened when required.

Cable sleeves can be used above or below grade. The sleeves are usually cast into place during construction of the foundation wall or installed during construction of the superstructure. The sleeves should be pitched to drain out of the building. Covers over the cables should be provided. Spare sleeves should be installed during initial construction.

Cable pits may be cast-in-place concrete or masonry openings through the control house foundation to permit access to the inside at floor level. A cover should be installed over the pit and a means to drain water provided.

6. <u>Lighting</u>

Two levels of lighting are normally provided in control houses. One level is for the convenience of operators and the other for working or construction purposes. Both systems should be installed to eliminate, as much as possible, reflection and glare from meter and relay faces. Both systems usually use fluorescent lamps for greater efficiency and economy.

An emergency dc operated incandescent system is recommended for most control houses. This system can be operated in case of failure of the ac system.

Additional information concerning control house lighting can be found in Chapter XIV.

7. <u>Control House HVAC Systems</u>

To maintain the functions and accuracy of electrical equipment installed in the control house, heating, ventilating and air-conditioning (HVAC) systems may be desireable.

In areas requiring heat only, unit electric space heaters are positioned throughout the control house for balanced heating. If both heating and cooling are required, electric heat pumps can be used. Several small units, or one large unit with a duct system for air distribution, can be utilized. Supplemental electric resistance heating coils may be required for heating in colder areas.

Baseboard radiation heating units can be used in rooms not reached by the main heating system. These rooms include offices, lavatories and storage rooms. The battery room is usually left unheated.

Temperature control levels may vary because of several requirements. Operating ranges of equipment must be considered, as well as economics. It is recommended that consideration be given to a dual control. Most stations will be unattended and, therefore, normal personnel comfort level is not required. However, for maintenance reasons, comfort levels are necessary.
The system then would normally maintain a minimum level based on equipment requirements with controls designed so that one or more additional units be used to raise the temperature to a comfort level suitable for maintenance personnel. In smaller control houses, this may be accomplished during maintenance periods by raising the thermostat controlling a small system.

If the control house is to be heated only, it is usually desirable to install power ventilation equipment for air circulation. The system should be sized for three to five air changes per hour. Power operated, thermostatically controlled roof ventilators and manually operated wall louvers should be placed to achieve good air circulation. Wall louvers should be positioned so that equipment does not interfere with air circulation. Fusible links should be provided to close the louvers in case of fire.

The battery room should be equipped with a gravity roof ventilator to remove corrosive and combustible gases. Power operated roof ventilators should not be used.

8. Control House Plumbing

Control houses should contain emergency eyewash facilities as a minimum. Additionally, very large, major locations may warrant a shower, lavatory, drinking fountain and maintenance sink.

A water supply, when required, may be obtained from an existing system or a private well on the substation site. A well should be capable of supplying 22 liters/min (5 gpm) at a minimum pressure of 172.4 kPa (25 psi).

Most substations with toilet facilities will require septic tank and drain field systems. These systems are designed and installed in accordance with local codes and regulations, obtainable through county health departments. Additional information can be found in the "Manual of Septic Tank Practice," Public Health Service Publication No. 526, US Department of Health, Education and Welfare.

Separation between a water well and a septic tank and drain field should be in accordance with local ordinances. In the absence of such information, a minimum of 15.2 m (50 ft) should be provided.

9. Communications

A commercial telephone is usually installed in the control house for external communications. Additionally, system telephones or voice channels over carrier systems may be used for systems communications.

Larger installations may include supervisory control and data acquisition systems (SCADAS) for remote control and monitoring of substation equipment.

For a detailed discussion concerning substation communications, see Chapter XVI.

CHAPTER XVI - COMMUNICATIONS

A. INTRODUCTION

Since substations are part of large interconnected power systems, methods of voice and data transmission among the various system parts are necessary to maintain satisfactory operation and control. Communications systems are used in protective relaying schemes to initiate on block tripping of power circuit breakers; in supervisory control systems to operate remote equipment; for transmission of data indicating equipment status and system conditions; and for voice communications for system operation and maintenance.

In this chapter the purposes of communications systems are presented. Methods of transmission are discussed and the equipment used is described.

B. PURPOSES

1. Relaying

Many relay schemes now in use require information to be exchanged between the two line terminals to effect high speed tripping over 100% of the line. Since these terminals are often many miles apart, some form of two way communication channel must be established between them. The information to be transferred is relatively simple two-state data in most cases and can utilize the more basic forms of modulation.

2. Supervisory Control

Many utilities now have a centralized energy control system from which some sort of system operation control is performed. It is usually expected that circuit breakers and tap changers will be operated, generation monitored and controlled, alarms reset and miscellaneous other on-off type functions effected over distances ranging from a mile or less to hundreds of miles.

3. Data Transmission

The energy control system receives various types of data from the power system. This data includes breaker status, tap changer position, amps, volts, watts, vars and other quantities, both digital and analog. Again, the data travels over distances ranging from a few miles to several hundred.

4. Voice Communication

Power system operation and maintenance requires the use of voice communication for daily operation and functioning of the power network. Voice communications are required between fixed points of operation and for mobile maintenance crews. The transmission of voice signals may take place via cable, radio, or the power system itself. The transmission facilities may make use of either leased systems or borrower owned facilities.

C. METHODS OF TRANSMISSION

1. Power Line Carrier

Power line carrier, one of the more common communication means found in power systems, is used for relaying, data and voice services. Carrier signal frequencies range from 30 kHz to over 300 kHz and are coupled directly to the power line through a coupling capacitor, a device which frequently doubles as a relaying and/or metering potential source. The signals are transmitted at a relatively low power level, typically 10 watts, and hence do not radiate appreciably from the power line. They must be received in a similar manner through a coupling capacitor connected to a carrier receiver at the other end of the line.

To confine the carrier signal as nearly as possible to one line section and to keep the signal from being effectively shorted through the high capacitance of the station bus and connected transformers, line traps are installed on the station side of the coupling capacitor to block the carrier signal.

Line traps are generally simple parallel L-C resonant circuits with the inductance in series with the coupled phase of the line. This inductance is rated to match the BIL, through current capability and short circuit withstand capability of any other major equipment on the line and so is physically large.

a. Tuning Elements

Besides the line trap and coupling capacitor, there are several other components involved in tuning and matching the transmitter output to the power system. These are:

(1) Line Tuner

The coupling capacitor provides the patch for the carrier signal to reach the power line itself. Since there are capacitive and inductive elements in the coupling capacitor and in the power system, a tuning network must be provided to match the transmitter output impedance to the impedance seen at the coupling capacitor input. This device, the line tuner, comes in several different configurations, depending on the tuning method selected. In addition, the line tuner assembly contains protective elements such as a gap with capacitor and a grounding switch. The assembly may be mounted in the coupling capacitor base or in a separate weatherproof cabinet.

(2) Hybrid

A hybrid is a special transformer used to combine carrier transmitter and receiver inputs and outputs in such a manner that transmitters and receivers may be connected to the same line tuner without mutual interference. A hybrid has one output and two inputs and is bi-directional so that the output may be connected to the line tuner and the inputs to a combination of transmitters and receivers without the receiver input being overloaded when the transmitter operates. Hybrids may be stacked; that is, one of the two inputs may be connected to another hybrid output resulting in three isolated inputs to the same line tuner. A limitation to this connection is that each hybrid reduces the power level by 3db. Thus, two stacked hybrids result in only 1/4 of the transmitter power reaching the line tuner from each hybrid terminal.

(3) L/C Units

Various combinations of series and parallel connected capacitors and inductors are available for use with special tuning schemes or as additional tuning elements in the line tuner package. In general, the manufacturer's recommendations should be followed in applying these units.

b. Tuning Methods

There are three basic methods of tuning carrier transmitters and receivers to the power line. They are:

(1) Single Frequency Resonant Tuning

A single frequency resonant tuned installation utilizes a combination of inductances and capacitances in the line trap and line tuner resulting in a combination frequency response that exhibits a single sharp peak centered about the selected frequency. Adjustment is available in both the trap and tuner, but both must be ordered by specifying a range of frequencies according to the manufacturer's catalog data. Single frequency resonant tuning is used less frequently as the available carrier spectrum becomes more crowded and it becomes more common to have several frequencies for multiple uses on a single line. Single frequency tuning results in the lowest transmission losses, but is least flexible from the standpoint of subsequent additional carrier frequencies for control, telemetering and relaying.

(2) Double Frequency Resonant Tuning

This coupling method is identical to single frequency tuning except that there are two closely-spaced sharp peaks in the frequency response. The losses are somewhat greater, but the availability of two frequencies can compensate for this small disadvantage. In addition, it is possible to use as many as four frequencies if they are selected so that none is more than the manufacturer's tolerance away from a peak. This is done by using hybrids on each of the two frequencies.

(3) Wide Band Tuning

The frequency response of a wide band tuning package is a relatively low peak spanning a wide range of frequencies. The obvious advantage is that a number of frequencies may be fed through the same line tuner.

A disadvantage is greater attenuation in the tuning package through more leakage to the bus side and higher impedance in the tuning package. The wide band line tuner is a simple high pass filter and series L/C units are frequently used to separate the various transmitter-receiver combinations. Hybrids should still be used to separate transmitters and receivers. Wide band tuning is becoming more pupular in spite of the increased losses due to the necessity of putting more functions on a line as relaying schemes become more elaborate and remote control and data functions are added.

c. Modulation Types

(1) On-Off

This simplest form of putting information on the carrier wave is only used with directional comparison or phase comparison blocking relaying. As its name implies, the carrier transmitter is normally de-energized. When it is keyed, it simply sends an unmodulated carrier which the receiver interprets as a blocking signal. Voice modulators are usually added so that the transmitter carrier can be modulated and thus provide an extra emergency or voice communication channel. Since a received signal in such a relay scheme does not result in a trip or attempted trip, it is perfectly safe to voice modulate the carrier.

The chief disadvantage of on-off carrier is its quiescent nature. The carrier is off most of the time and, if a component fails during this period, there will be no indication of the failure until the scheme is called upon to operate. If it must block for an external fault at that time, a false trip can occur. Many utilities avoid this situation by applying a carrier checkback scheme. This scheme periodically initiates a characteristic series of carrier bursts from one end of the line. The other end recognizes the test transmission pattern and responds similarly. Receipt of this response at the initiating end verifies both transmitters and receivers.

(2) Frequency Shift Keying (FSK)

This modulation method finds widespread use in most relaying, control and data transmission schemes. An unmodulated carrier is sent continuously and is termed the "guard" or "space" signal. When a trip or data signal is desired, the guard or space signal is shifted up or down a few percent and the shifted signal is termed the "trip" or "mark" signal. In general, relaying literature uses the trip and guard nomenclature while mark and space will be found in most data and control literature. Trip and guard signals are separated by very accurate filters on the inputs of the receiver.

The advantage of this scheme, particularly for relaying, is the channel monitor capability provided by the continuous transmission. If, at any time, the guard signal disappears without an immediate trip signal, the channel is presumed to have failed and an alarm can be energized. Additional channel security can be obtained by biasing the receiver discriminator to the guard side. A white noise burst, therefore, will produce a small net guard output which can be overcome by a transmitted trip signal even during the noise burst. This feature makes it possible to drive an FSK carrier signal through an arcing fault on the protected section.

Until recently, the only real disadvantage of this scheme was that it was not possible to use voice on an FSK channel. Within the past year, however, a major manufacturer has developed a voice modulator for use with his FSK carrier equipment.

(3) Single Sideband (SSB)

This modulation type is used extensively in other countries where its multi-channel capability is important due to the lack of a reliable and extensive telephone network such as exists in this country. In those areas, power systems must provide their own basic voice communications and the power system itself is an excellent medium. Here, however, SSB carrier has found little use primarily due to its high cost.

Basically, the carrier signal is modulated with voice or data signals resulting in the transmission of the carrrier plus two sidebands containing the carrier plus the modulation frequency and carrier minus the modulation frequency which is conventional. Since all the desired information is in each sideband, the carrier and either sideband can be eliminated resulting in a suppressed carrier, single sideband signal having one-half the band width of a transmission. It is then possible to transmit two voice channels in the bandwidth formerly occupied by one voice channel.

Sophisticated equipment is available whereby, with a system of subcarrier frequencies, many channels in multiples of two can be transmitted.

2. Audio Tone

Audio tone equipment operates in the frequency range from 1000 Hz to about 3000 Hz. Frequency shift keying is the only modulation type available; voice modulation cannot be used.

Audio tone is used primarily as a short distance medium over wire lines. If a telephone pair can be leased from the telephone company, then this channel can be cost competitive with carrier for relaying and data communications. FSK modulation provides ample security and in most cases for most telephone companies, reliability is also high. Additional security is available in the form of broad band noise detection and frequency translation detection.

Broad band noise detection is simply a wide band receiver with no corresponding transmitter. If this receiver output exceeds a certain level, a noise alarm is actuated and all channels squelched off. Frequency translation detection utilizes a single unmodulated channel. If the output from this receiver drops, the translation alarm is actuated. This feature is most commonly used with microwave or other multi-channel configurations where a problem in the multiplex equipment can cause frequency shifts.

3. Carrier or Audio Tone on Shield Wire

The chief distinction of this method is the medium rather than the equipment. Transmitters and receivers are the same as employed in other carrier and audio tone systems. However, in this scheme they are coupled to insulated transmission line shield wires. EHV shield wires are sometimes insulated to reduce losses from induced circulating currents. The usual insulation level is 15 kV with gaps on the insulators to conduct lightning strokes to ground.

The coupling is usually between two such insulated shield wires through a special coupler containing matching networks, capacitors, protective gaps and an insulating transformer. This equipment is required to protect the communications equipment from the high energy levels present on such shield wires during lightning strokes.

In general, this method is not used for protective relaying due to the uncertainty of successful communication during lightning strikes. It has found more application for data and voice communications as a low cost alternate in those cases where the decision to insulate the shield wires had already been made on the basis of inductive loss prevention.

4. Microwave

Microwave systems have been finding more use on power systems in recent years as the requirements for dedicated voice and data communications increase. Due to the high expense of the RF equipment and antenna towers, microwave is generally used where there is a requirement for a large number of channels between two points. Transmission is line-of-sight only, necessitating intermediate repeater stations for long paths. The cost per channel is relatively low as long as most of the available channels are used and the patch length is not excessive.
Microwave systems presently employed use transmission frequencies of 980 mHz and up which accounts for the high channel capacity and line-of-sight transmission. There is relative freedom from many forms of interference, but path fading and other forms of distortion can be problems. Signals are inserted in the audio range and multiplied up to the RF frequency. The input may be voice or FSK audio tones.

5. Wire Lines

Wires lines leased from the telephone company are used in many cases for routine voice and data traffic. A detailed treatment of wire line protection and installation is available in other REA literature and so will not be covered again here. A few general points should be touched briefly, however:

> Wire lines entering substation premises must have special protection against induced currents and rise in station ground potential.
>
> Communications and Data Channels:
>
> These circuits may use carbon blocks or similar devices that will remove the circuit from service when they operate.
>
> Relaying Channels:
>
> These circuits must remain in service during and after a power system fault. For audio tone circuits, high voltage insulating transformers, gas tubes with mutual drainage reactors and possibly neutralizing transformers may be required. Pilot wire circuits require neutralizing transformers whenever dc monitoring is used.

Voice traffic in most areas can be handled over wire lines since occasional interruptions can be tolerated in voice and data transmission. Relaying can be performed over wire lines only if the responsible telephone company can be relied upon to provide circuits that are adequately protected against the effects of nearby power system disturbances.

CHAPTER XVII - INSPECTION

A. PURPOSE

The purpose of this chapter is to recommend procedures for the establishment of an inspection program for substation equipment, structures and other devices. A recommendation for the frequency of these inspections is included.

Guidelines for the required inspection procedures are discussed in this chapter. The guidelines are necessarily general. They must be tailored to meet the requirements of a specific site as well as for the equipment at this site.

In all cases, specific equipment manufacturer's recommendations as contained in the equipment instruction books shall be observed and factored into the procedure as outlined.

Certain test and maintenance procedures should be performed as the inspections are made. The recommendations should therefore be coordinated with those contained in the chapters covering Testing and Maintenance.

B. GENERAL

It is essential that inspections of substation equipment, structures and other devices be made periodically. In addition to this periodic inspection, other inspections may be required to ascertain the cause of particular problems or when equipment is placed in service or when the substation or portions thereof are taken out of service.

1. Records

A record system should be maintained at each substation site. This record system should provide at least the following:

a. Equipment Records

This includes equipment nameplate data together with specific transformer or voltage regulator tap connection details, trip settings, etc., for all equipment.

b. Inspection Records

These records, when accurately maintained, permit evaluation of the serviceability of equipment to be made at any time.

c. Inspection Check List

This list, derived for a specific substation, contains all items to be inspected during periodic inspections.

2. Safety

In order that all inspection procedures may be fulfilled in a safe and proper manner, it is essential that all personnel be thoroughly trained, in proper and safe procedures. This includes but is not limited to:

Familiarity with operating procedures for the substation.

Familiarity with protective and interlocking schemes.

Knowledge of the capabilities of the equipment.

The proper use of safety equipment.

The knowledge and proper use of first aid procedures and equipment. .

The knowledge and proper use of equipment grounding techniques.

Whenever any defects or improper conditions are noted, they should be repaired as soon as possible.

Safety regulations must be observed at all times. Proper distances must be maintained from energized equipment. The following distances are the minimum clearances that must be maintained between personnel and energized equipment:

750 to	3,500 volts	. . . . .	30 cm	(1 ft)
3,501 to	10,000 volts	. . . . .	60 cm	(2 ft)
10,001 to	50,000 volts	. . . . .	1.0 m	(3 ft-4 in)
50,001 to	100,000 volts	. . . . .	1.60 m	(5 ft-4 in)
100,001 to	250,000 volts	. . . . .	3.0 m	(10 ft)

Proper safeguards such as danger signs, temporary barriers, etc., should be employed for the safety of persons close to, but not engaged, in the work to be performed.

C. PERIODIC INSPECTIONS

The substation in total and the individual items of equipment contained therein should be periodically inspected. The recommended frequency of these inspections is as follows:

Visual Inspection of Total Substation . . . Monthly
Inspection with Infra-Red Photography . . . Annually
Detailed Inspection of Major Equipment . . . Annually
Internal Inspection of Transformers
and Regulators . . . . .Triannually

1. Visual Inspections

Visual inspections should encompass the total substation area including the site, the control house and all equipment and structures. This inspection will be made with the substation energized. Therefore, all inspections should be made from ground level, to assure adequate safety clearances from energized parts. Binoculars should be used to view buses and other equipment located on structures.

Special care should be used when ground connections are checked, since a high voltage could develop across any gap created between a ground cable and a piece of equipment, particularly under fault conditions. For this reason, ground connections shall not be removed for any reason while the substation is energized.

The following describes details of visual inspection:

a. Power Transformers

Inspect control cabinet, control relays, contactors, indicators and operating mechanism.

Look for loose, contaminated or damaged bushings, loose terminals and oil leaks.

Check oil levels in main tanks, tap changer compartment and bushings.

Inspect inert gas system (when applicable) for leakage, proper pressure, etc.

Record operations counter reading for load tap changer.

Observe oil temperature. It should not exceed the sum of the maximum winding temperature as stated on the nameplate plus the ambient temperature (not to exceed 40°C) plus 10°C. Generally, this oil temperature does not exceed 95° and 105°C for 55° and 65°C winding temperature rise units, respectively, since the ambient temperature rarely exceeds 30°C for periods of time long enough to cause an oil temperature rise above these points.

b. Voltage Regulators

Perform same inspections as listed for power transformers (as applicable).

Place regular control in manual position and operate regulator over small range only.

Return control to automatic and verify that the regulator operates to return the output voltage to normal.

Record operations counter reading.

c. Oil, Vacuum, SF_6 and Air Blast Circuit Breakers

Check for loose, contaminated or damaged bushings, loose terminals and oil leaks.

Check oil level in bushings and main tank (if applicable).

Record the number of operations. If breaker has not operated during the preceeding two months, bypass and operate breaker, simulating relay action by placing a jumper across the tripping contact studs on the back of the relay. Allow breaker to go through its sequence to check its operation.
Inspect contact areas on main plug-in assembly for signs of overheating or arcing.

d. Fuses

Observe level and color of liquid in liquid filled fuses. Changes in color of liquid may indicate contamination.

Observe condition of contact surface of fuse clips.

Check for broken or cracked supporting insulators and for contamination.

e. Surge Arresters

Check for cracked, contaminated or broken porcelain, loose connections to line or ground terminals and corrosion on the cap or base.

Check for pitted or blackened exhaust parts or other evidence of pressure relief.

If discharge counters are provided, check connections and record the number of operations.

f. Buses and Shield Wire

Inspect bus supports for damaged porcelain and loose bolts, clamps or connections.

Observe condition of flexible buses and shield wires.

Inspect suspension insulator for damaged porcelain (include line entrances).

g. Capacitors

Observe condition of fuses.

Inspect for damaged tanks and bushings and for leakage of the dielectric.

h. Disconnects and Other Switches

Check for cracked, contaminated or broken porcelain, loose connections and corrosion to metal parts.

Observe condition of contact surfaces and area around them.

Observe condition of arcing horns on air break switches (when applicable).

Inspect operating mechanism.

i. Control and Metering Equipment

Check current and potential transformers for damage to cases, bushings, terminals and fuses. Verify the integrity of the connections, both primary and secondary.

Observe the condition of control, transfer and other switch contacts, indicating lamps, test blocks and other devices located in or on control cabinets, panels, switchgear, etc. Look for signs of condensation in these locations.

Examine meters and instruments externally to check for loose connections and damage to cases and covers. Note whether the instruments are reading or registering.

Open and close each potential switch on the test block to determine whether the speed of the meter disk is affected. Repeat the process with the current switches. Changes of speed should be approximately the same for each meter element.

Make an external examination the same for each meter element.

Make an external examination of relays, looking for damaged cases and covers or loose connections.

Check station battery for loose connections, low level or low specific gravity of the electrolyte. Record temperature.

Inspect station battery charger. Check charging current and voltage. Observe ground detector lamps for an indication of a ground on the dc system.

j. Structures

Inspect all structures for loose bolts and nuts.

Observe any damaged paint or galvanizing or signs of corrosion.

k. Grounding System

Check all above grade ground connections at equipment, structures, fences, etc.

Observe condition of any flexible braid type connections.

l. Cable

Inspect for signs of deterioration of the insulation.

Check for cable displacement or movement.

Check for solder "runs" or loose connections.

m. Substation Area (General)

Verify existence of appropriate warning signs.

Check indoor and outdoor lighting systems for burned-out lamps or other component failures.

Verify that there is an adequate supply of spare parts and fuses.

Observe the condition of hook sticks.

Inspect the fire protection system and the provisions for drainage of leaking oil.

Observe for bird nests or other foreign materials in the vicinity of energized equipment, buses or fans.

Observe the general condition of the substation yard, noting the overall cleanliness and the existence of low spots that may have developed.

Observe the position of all circuit breakers in the auxiliary power system and verify the correctness of this position.

2. Inspection With Infra-Red Photography

Consideration should be given to supplementing the visual inspections with the periodic use of infra-red photography or other infra-red techniques. Photography is favored, since it will provide a more permanent record of areas requiring closer observation until trouble conditions can be corrected. A less expensive alternate method employs the use of a self-calibrating portable indicating infra-red unit in coordination with a Polaroid camera.

The use of infra-red techniques will permit locating loose connections, overloading of conductors, localized overheating in equipment or similar conditions before they become serious.

3. <u>Detailed Inspection of Major Equipment</u>

Annual inspections are recommended for certain major equipment and portions of the auxiliary system. These inspections are detailed and will therefore require that the piece of equipment being inspected be de-energized.

Annual inspections are recommended for the following equipment:

Disconnects and Other Switches

Metal-clad switchgear

Air Circuit Breakers

Oil Circuit Breakers

Air Blast and SF_6 Circuit Breakers

Vacuum Circuit Breakers

The annual inspections are in addition to the bi-monthly inspections suggested in Paragraph C and should be conducted simultaneously. Details are described in the following paragraphs.

a. <u>Disconnects and Other Switches</u>

Inspect moving and fixed contacts. Verify adequacy of wiping action. Check contact pressures.

Inspect spring assembly for signs of corrosion (air break switches only) and tighten bolts.

Inspect current shunt around spring assembly and tighten all bolts.

Check fluid levels in gear boxes (when applicable).

Check blade alignment on gang-operated switches.

Inspect switch base and other galvanized parts for corrosion.

b. Metal-clad Switchgear

Inspect for damage to enclosures, doors, latching mechanisms, etc.

Inspect bus supports for signs of tracking.

Verify that all joints are tight.

Check alignment of all disconnect devices, both primary and secondary, including those for potential transformers.

Inspect terminal connections and condition of wiring.

Check rails, guides, rollers and shutter mechanism.

Inspect cell interlocks, cell switches and auxiliary contacts.

Inspect control, instrument and transfer switches.

Inspect for broken instrument and relay cases, cover glass, etc, and check for burned-out indicating lamps.

c. Air Circuit Breakers (15 kV and Below)

Inspect contacts for visual signs of overheating. Check contact clearance, contact wipe, toggles, latches, position indicator, auxiliary contacts, etc.

Inspect hardware and check wire connections for tightness.

Inspect arc interruption chambers.

Inspect relay contacts.

Check fuse clips for tightness.

Check condition of bushings, porcelains and contact surfaces.

Check load conductor terminations.

Check current transformer connections.

Check grounding connections.

Check lifting or racking mechanism (if applicable).

d. Oil Circuit Breakers

Check compressor operation, including operation of all pneumatic switches and their operating set point.

Check for air leaks.

Check compressor belts.

Check latching mechanisms, relay contacts and fuse clips (for tightness).

Untank breaker and check:

Pole units, contacts, bayonets, interrupters and resistors for signs of heating.

Hardware and wiring connections for CTs.

Alignment of contacts.

Operating mechanism and leakage.

Lift rod and toggle assembly.

NOTE: Untanking is required only when specified in the Instruction Book. This is normally done after a trip operation when the magnitude of current interrupted approaches the maximum capability of the breaker or after a particular number of operations. In the latter case, the time of inspection should be coordinated with the annual inspection whenever possible.

CAUTION - The manufacturer's recommendations must be observed with respect to manual operation of the circuit breaker without oil.

e. Air Blast and SF_6 Circuit Breakers

Perform all checks and inspections as outlined in Subparagraph C. for air circuit breakers.

Inspect compressor system, including belts, pneumatic switches, contactors, relays and other auxiliary devices.

Inspect gas or air piping for signs of deterioration.

Inspect all air or gas seals and "O" rings.

Inspect wiring connections and hardware for CTs.

f. Vacuum Circuit Breakers

Perform all checks and inspections as outlined in Subparagraph C. for air circuit breakers except delete all reference to inspection of main contacts or arc interruption chamber.

4. Internal Inspection of Transformers and Regulators

Internal inspections require considerable time out of service for the equipment involved. Therefore, they should be scheduled, whenever possible, to coincide with planned substation outages.

Since large equipment is frequently required for use in disassembly operations, it is essential that all aforementioned safety precautions be rigidly followed. Details of these inspections follow:

a. Transformers

Open type transformers (those that may breathe free air) that have not been so inspected for at least three years should, if time permits, be given an internal inspection consisting of the following:

Lower the oil level to expose the top of the core and coil assembly.

Look for evidence of corrosion of tank walls and other metal parts.

Check connections for tightness.

Check to see whether sludge deposits have accumulated in ducts or other locations. Such deposits impede the circulation of oil and thus any appreciable amount should be removed.

Samples of oil taken from the bottom of the tank should be tested to determine the water content. See Chapter XVIII - Testing.

b. Regulators

Voltage regulators should be inspected using the same criteria as indicated for open type transformers. It may be necessary to untank the core and coil assembly to complete the inspection.

D. NON-PERIODIC INSPECTIONS

Whenever a substation, or any part of it, is de-energized for any reason, a detailed inspection should be made of those items of equipment that cannot be observed at close range when energized. In particular, this includes:

Transformers
Regulators
Fuses
Disconnects
Air Break Switches
Load Interrupter Switches
Grounding System
Circuit Breakers
Oil Circuit Breakers
Structures
Buses

The extent of the inspections may be limited because of the time available during the period of de-energization; however, it is essential to perform as many items as possible. Details of the inspection procedures are outlined in the following paragraphs.

1. Inspection of Porcelain

All insulators and equipment bushings should be inspected for chipped petticoats and fractured or cracked porcelain. Flashovers in the past may have damaged a portion of the glazing on the porcelain. This inspection should be made at close range.

2. Fuses, Disconnects and Other Switches

Current carrying portions should be inspected to verify that proper tensions are being maintained, contact surfaces are free of discoloration (possibly caused by overheating) and that all bolts and nuts are tight.

3. Buses

All bus fittings, connectors, couplers, etc., should be inspected to verify that all bolts are tight and that there is no indication of hot spots, as evidenced by discoloration. The integrity of the stranding of flexible buses at strain clamps should be verified.

4. Transformers

Open type transformers that have not been internally inspected for at least three years should be checked in accordance with details contained in paragraph 4. Internal Inspection of Transformers & Regulators.

5. Transformer On-Load Tap Changers

If the number of operations of the tap changer contactor is approaching mandatory inspection and possible replacement of the contacts per the manufacturer's recommendations, this inspection might best be performed at this time. In this case, the tap changer compartment must be drained of oil. All portions of the mechanism should be inspected for excessive wear and proper adjustment.

6. Regulators

Voltage regulators that have not been internally inspected for at least three years should be checked in accordance with details contained in paragraph 4. Internal Inspection of Transformers & Regulators.

7. Oil Circuit Reclosers

These devices should be inspected per instructions in REA Bulletin 161-14, "Maintenance of Oil Circuit Reclosers and Sectionalizers."

8. Circuit Breakers

Circuit breakers should be inspected in accordance with the applicable procedures contained in the paragraph entitled "Annual Inspections" if they have not been so inspected within the previous 12 months.

9. Grounding System

All accessible ground connections should be checked for tightness, and the overall ground grid resistance should be measured if it has not been done for a number of years. Since it is desirable to disconnect shield wire grounds and system neutral connections to make this measurement, the total substation must be de-energized for these tests. See Chapter XVIII - Testing, for details.

10. Structures

All structures in close proximity to buses, energized portions of equipment, etc., should be inspected and necessary repairs to galvanizing and painted surfaces made. See Chapter XIX - Maintenance, for details.

CHAPTER XVIII - TESTS

A. PURPOSE

The purpose of this section is to recommend procedures for the establishment of a testing program for substation equipment. A recommendation for the frequency of these tests is also included.

B. GENERAL

Tests of substation equipment are required to fulfill at least the following functions:

To prove the integrity of a piece of equipment at the time of acceptance.

At periodic intervals of time to verify the continued availability of the equipment.

At time of failure of a piece of equipment so as to be able to determine the specific requirements for repair.

The types of tests to be performed for each of the above categories varies. Guidelines are therefore included to assist in this selection. The guidelines are, of necessity, quite general in nature and as such, must be tailored to meet the requirements of the specific equipment.

The testing schedules should be coordinated with the inspections as detailed in Chapter XVII. In addition, scheduled outages should be utilized to the greatest extent possible as periods for testing since certain equipment is unavailable for test unless large portions of the substation are de-energized.

Upon completion of tests, provisions should be made to follow-up with repeat tests where required and repairs where the need is indicated by the test results.

In all cases, specific equipment manufacturer's recommendations as contained in the equipment instruction books must be factored into the testing procedures outlined.

1. Records

A records system, as outlined in Chapter XVII - Inspection, should be maintained for each site. In addition to the details contained therein, these records should contain at least the following information:

a. The name, date and results of all tests performed.

b. The date when the equipment should be again tested.

c. Any requirements for follow-up or special tests that are required due to indications of potential trouble.

2. Safety

Some tests, particularly those requiring gas or oil samples may be performed without removing the equipment from service. The personnel utilized to perform such tests or obtain gas or oil samples must observe safety regulations at all times. Special attention is called to the minimum clearances provided in Chapter XVII. Whenever possible, temporary barriers should be provided to isolate the equipment being tested from adjacent energized equipment.

Testing equipment is usually very specialized equipment. Its use therefore, must be restricted to those personnel who have been adequately trained. Improper use of the equipment may expose both the user and the equipment to hazards.

The analyses of properly obtained test data is again a specialized technique. Failure to recognize trends while conducting a test could be injurious to the personnel, the test equipment and the equipment being tested. Failure to recognize trends in data obtained at different times can result in the failure to detect potential problems in sufficient time to permit an orderly and timely removal of equipment from service.

C. DETAILED REQUIREMENTS

As indicated herein before, testing is performed to accomplish three distinct functions; the acceptance of equipment, the periodic verification of its integrity and to permit a better analyses of its failure.

1. Acceptance Tests

Acceptance tests are performed after receipt and erection or installation of equipment at the site. The results of these tests are compared with the specifications, where applicable, evaluated and compared with acceptable norms and factory test data and when found acceptable, recorded for future reference. The recommended acceptance tests, delineated by type of equipment, are indicated in Table XVIII-1, which is located at the end of this Chapter.

2. Periodic Tests

Periodic tests, those used to establish the continuing quality of the equipment, are conducted at varying intervals of time, depending upon the type of equipment. Table XVIII-2, also located at the end of this Chapter, provides a tabulation of the recommended periodically conducted tests together with the recommended interval of time between tests.

3. Tests After Failure

Testing conducted after an equipment failure is performed so to determine, to the greatest extent possible, the location, magnitude and cause of the failure. Such data, when properly obtained, is used in determining whether the equipment can be repaired in-place or needs to be shipped to a repair shop. The tests to be performed in such cases are the same as listed in Table XVIII-2 except that high voltage tests are not usually performed.

D. DESCRIPTION OF TESTS

Descriptions of the tests indicated in Tables XVIII-1 and 2 are contained in subsequent paragraphs together with ranges of test values which are considered acceptable.

Specific details for application of the test equipment are in the instruction book for that item of test equipment. A brief reference to applicable test equipment is also included with the description of each test. The ranges and outputs indicated are considered appropriate for the tests and thus should not be varied significantly.

1. <u>Insulation Resistance Test</u>

This test is performed to verify the integrity of the insulation as is used in all types of electrical equipment. This includes transformers, circuit breakers, cables, motors, switches, etc.

a. <u>Equipment Required</u>

500/1000/2500 volt "Megger", either motor driven or voltage regulated.

b. <u>Typical Minimum Resistance Values</u>

AC Motors, 75°C	120 Volt - 1.12 megohms
	208 Volt - 1.20 megohms
	240 Volt - 1.25 megohms
	480 Volt - 1.50 megohms
DC Motors, 75°C	All Voltages - 1.00 megohms
High Voltage Circuit Breakers, 20°C	10,000 megohms
High Voltage Bushings, 20°C	10,000 megohms

Insulated Cable - Varies as a function of type and thickness of insulation - See IPCEA Standards

Transformers, Oil Filled, 20°C where E is voltage rating of winding under test and kVA is rated capacity of the winding under test	$\frac{1.5E}{KVA}$
Transformers, Dry type, 20°C where E and kVA are as defined above	$\frac{30E}{KVA}$

Other Equipment - Refer to Manufacturer's Data

2. Power Factor Test

This test is used to measure the power factor of the insulation in all types of electrical equipment and cable. The test must be conducted at temperatures above 0°C since ice is a relatively good conductor. This test provides an indication of the quality of the insulation. Values obtained during the acceptance tests are compared with expected ranges of values determined from similar equipment. After the initial tests, comparison is made between values obtained at different times so as to establish a trend and thus anticipate potential troubles. Whenever possible, power factor tests should be incorporated into the routine factory tests for equipment. The acceptance test values may then be directly compared with the factory values.

a. Equipment Required

Test equipment such as manufactured by the Doble Engineering Company or James G. Biddle Company or a Schering Bridge are among those suitable for this purpose.

b. Acceptable Values

Acceptable values of power factors for various items of equipment are provided with the test equipment. Additionally, equipment manufacturers frequently provide this data for their specific equipment. The following values for a few common items are provided for reference only, so as to illustrate the very low magnitudes of power factors encountered:

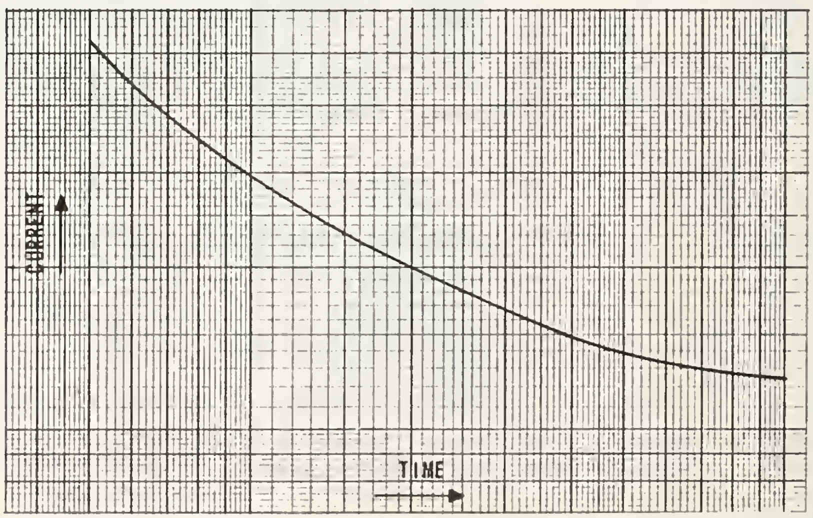
	% P.F. at 20°C
Bushings, Condenser and Oil Filled	0.5
Bushings, Compound Filled	2.5
Transformers, Oil Filled, New	0.5
Transformers, Oil Filled	1.0 - 2.0
Cable, PILC	0.3
Cable, Varnish Canibric Insulated	4.0 - 8.0
Cable, Rubber Insulated	4.0 - 8.0

3. DC High Potential Test

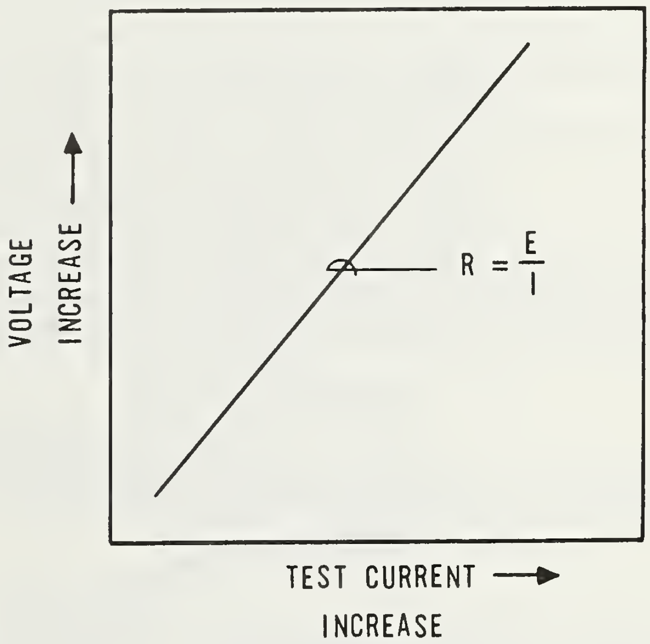
This is a test of the dielectric strength of insulation. It is utilized to determine the quality of the insulation in electrical equipment, particularly items with solid dielectrics such as porcelain, rubber, PVC, PE, Micarta,etc. It is not generally used for on-site testing of equipment windings, with the exception of motor-generator windings, or on oil filled equipment.

Extreme care must be exercised when applying the test voltage so as to avoid equipment damage. Successful withstand of the voltage indicates satisfactory dielectric strength. In addition, a comparison of the charging current between tests over a period of time will indicate the degree of deterioration of the insulation as well as an examination of the plot of the leakage current vs. time during the "soak" portion of the test.

Theoretically the steady state test current should be constant with time for any one value of applied voltage. This constancy with time is a good indication that the insulation under test can withstand the voltage being applied. Any tendency for this current to steadily increase with time at constant applied voltage is a warning that the insulation under test may be damaged by a continuation of the test at that voltage. A plot of total test current versus time should result in a curve as shown.



For an insulation test that is clean, dry and free of voids, the test current at the lower voltage levels should not only be constant with time, but should increase lineally at each higher voltage according to Ohm's Law. A plot of steady state test current versus voltage will result in a graph as shown.



a. Equipment Required

DC High Potential set, similar to those manufactured by Associated Research, Inc., James G. Biddle Company., Hipotronics Inc., Von Inc. and others (0-100 kV or higher, as required)

b. Typical Test Voltages

Acceptance Tests:	80-85% of factory test voltage
Periodic Tests:	60-65% of factory test voltage (55-60% of factory test voltage with PILC cable with neoprene jacket)

4. Dielectric Absorption Test

This test is again a test of the quality of the insulation. It is applicable to transformers, regulators and other similar devices as well as shielded high voltage power cable. It is not possible to provide a range of values for the results of this test. Its primary function is to provide an indication of deterioration prior to complete failure.

This test is performed by charging the insulation under test with an insulation resistance test set. The test is applied for a period of time sufficient to fully charge the cable. Resistance readings are taken every fifteen seconds during the first three minutes and at one minute intervals thereafter. The test shall continue until three equal readings are obtained. This final reading shall be recorded. All windings or other conductors (in the case of a cable) not being tested must be grounded. The tank (or shields) must be grounded also.

a. Equipment Required

2500 volt motor driven megger or multi-range megger with voltage regulator.

b. Typical Readings

Condition	60:30 Sec. Ratio	10:1 Min. Ratio
Dangerous	-	less than 1
Poor	less than 1.1	less than 1.5
Questionable	1.1 to 1.25	1.5 to 2.0
Fair	1.25 to 1.4	2.0 to 3.0
Good	1.4 to 1.6	3.0 to 4.0
Excellent	above 1.6	above 4.0

5. AC Over-Potential Test

This test is performed to verify the integrity of the insulation in low voltage devices (600 volt and below) and associated wiring. Specific manufacturer's recommendations should be observed before applying this test to solid state components. The test consists of applying an AC voltage to the device for one minute and verifying the successful withstand of this voltage.

a. Equipment Required

AC High Potential set, similar to those manufactured by Associated Research, Inc., James G. Biddle Company or Hypotronics Inc. (0-2500V. output or higher as required)

b. Test Voltages

Acceptance Tests - Twice the operating voltage plus 100 volts, but no less than 1500 volts

Periodic Tests - 1.7 times the operating voltage

6. Contact Resistance Test

This test is used to measure the resistance of the main contacts of a circuit breaker. A rise in resistance is an indication of the need for maintenance or replacement of the contacts.

a. Equipment Required

A "Ducter" low resistance ohmmeter as manufactured by the James G. Biddle Company, or similar.

b. Typical Readings

Refer to data provided by manufacturer with respect to the maximum permissible resistance. Typical ranges however, are as follows:

Circuit breakers:	10-50 micro-ohms (medium voltage)
	50-350 micro-ohms (high voltage)
Reclosers:	50-200 micro-ohms

7. Winding Resistance Test

The winding resistance in a motor, transformer, regulator, etc., is not subject to change unless turns are open or short circuited. An accurate measurement of the resistance at time of acceptance will thus permit future assessment of winding faults. Periodic checks will disclose shorted turns before further problems occur. Results must be corrected for temperature. See ANSI Standards for details.

a. Equipment Required

Kelvin Bridge suitable for measuring less than 1-ohm.

8. Insulating Oil Tests

Neutralization number, interfacial tension, dielectric strength, color and visual examination tests should be performed as described in IEEE No. 64-"Guide for Acceptance and Maintenance of Insulating Oil in Equipment". A comparison of the values obtained for each test over a period of time will indicate the gradual deterioration of the oil unless oil treatment has been performed. Sudden or accelerated changes in the dielectric strength are not normally encountered. Should a large change occur, a complete inspection of the transformer should be performed rather than just instituting a treatment program.

A power factor test of the oil is a somewhat less accurate method of evaluating the dielectric strength of the oil than the ASTM standard method. It is a suitable substitute if suitable facilities for the ASTM test are not available.

It should be used, however, for periodic routine tests only. Tests conducted in association with trouble finding should be by the ASTM method.

a. Equipment Required

Two options exist with respect to the performance of insulating oil tests. The option adopted is generally a function of the size of the system, i.e., whether the need for such tests is great enough to warrant the procurement of all equipment required. The two possibilities are:

Submit an oil sample to a qualified laboratory for determination of the neutralization number, interfacial tension, dielectric strength, gas analysis and color test.

Perform tests on site where possible, using the following equipment and methods:

(1) Neutralization number - Calculate value by color-indicator titration method, ASTM D1534

(2) Interfacial tension - Measure using a surface tension tester such as is manufactured by Technical Associates or Fisher Scientific Co., ASTM D2285

(3) Color Test - Test should be performed in accordance with ASTM D1524 which includes a field test procedure. Submitting a sample to a testing laboratory is preferred.

(4) Dielectric strength - Measure using a tester such as the General Electric Portable or Hypotronics Oil tester, ASTM D877

When the results of the insulating oil tests reach the following values, consideration should be given to performing the operation indicated:

Neutralization number - When number exceeds 0.4 for transformers or 0.5 for circuit breakers, the oil should be reclaimed - See IEEE No. 64.

Interfacial tension - When tension is less than 18-dynes/cm, oil should be reclaimed - See IEEE No. 64.

Dielectric strength - When dielectric strength is less than 22 kV with a standard gap, recondition oil by filtering.

Color Test - When color exceeds 3.5, the oil should be reclaimed - See IEEE No. 64.

Visual Examination - If oil is cloudy, dirty or contains visible water, the oil should be reclaimed. See IEEE No. 64.

9. Combustible Gas Analysis

A combustible gas analysis is performed to determine the amount, if any, of various types of combustible gases in the transformer gas cushion. These combustible gases are produced over a period of time by

small magnitude turn-to-turn or other internal arcing faults. Internal arcing involving the core or other steel parts may result in particles of carbon in suspension also. Upon detection of combustibles, testing should be repeated at shorter intervals of time so as to assure removal of the unit from service before major trouble occurs.

a. Equipment Required

It is generally desirable that a sample be submitted to a laboratory for a complete analysis. This will provide details of the specific gases present.

Results indicating 0.5 to 5.0%, by volume, of combustible gases, indicate the probable existence of an incipient fault. This necessitates close observance of the unit and the need for additional tests at shorter intervals of time. With percentages higher than 5%, it is recommended that the unit be taken out of service for detailed internal inspection. It is possible to examine the insulating oil itself for dissolved gases and carbon in suspension. This should be accomplished in a laboratory. Similarly, the gas collected in a "Buchholtz" relay should be analyzed in a laboratory.

10. SF_6 Gas Analyses

SF_6 gas used in circuit breakers is subject to contamination due to the products released during the interruption of current. This contamination increases with the severity of the fault and with the deterioration of the breaker contacts. Specific tests are not normally performed, however, since the gas should be reconditioned on a regular basis in accordance with the manufacturer's recommendations.

Refer to specific equipment instruction books for additional requirements, if any.

11. Timing Test

A timing test is performed at time of acceptance and again after all adjustments or replacements of con-

tacts in circuit breakers. The test is used to verify that all poles of the circuit breaker and all series contacts in each pole are operating simultaneously. The circuit breakers should be timed to as close as possible to the tolerances provided by the manufacturer.

a. Equipment Required

Depending upon the type of circuit breaker being tested, one of the following test devices should be used:

(1) A circuit breaker operation analyzer such as one manufactured by the Cincinnati Clock and Instrument Co. may be used for breakers having a common operating shaft between poles such as the case with oil circuit breakers.

(2) A multi-channel oscillograph is required for air blast and most SF_6 type circuit breakers. This oscillograph must have sufficient channels so as to provide one channel for every main contact, every resistor contact and also for event marking such as time of energization of the operating circuit. In all, probably a 24 channel unit is required. The unit should have a frequency response of 150-5000 cycles per second.

12. Motion Analyzer Test

The motion analyzer test is conducted to verify the good condition and proper adjustment of the mechanical operating linkages of a circuit breaker. A graphical representation of the elapsed time versus distance traveled is plotted. Any wear or poor adjustment will result in a non-uniform curve. This test should be conducted in conjunction with the timing test.

a. Equipment Required

Circuit breaker operation analyzer as manufactured by the Cincinnati Clock and Instrument

Company, M & G Instrument Company or Barnes Engineering Company.

13. Series Overcurrent Test

All reclosers and low voltage power circuit breakers having series trip devices should be tested periodically to verify the calibration and proper operation of the device. The test is performed at a number of current levels so as to verify the current versus time operating characteristics and the minimum instantaneous trip current level, if applicable.

a. Equipment Required

Test equipment similar to those manufactured by Multi Amp Corporation, General Electric Company, EIL Laboratories, etc., is required to provide a single phase calibrated current source.

14. Turns Ratio Test

A turns ratio test is performed periodically as an aid in detecting turn-to-turn short circuits in power and instrument transformers. When evaluating the initial test results, proper consideration must be given to manufacturing tolerances.

a. Equipment Required

A turn ratio test set as manufactured by the Biddle Company is a convenient device. The test methods outlined in ANSI Standards require less specialized equipment.

15. Polarity Test

Polarity tests should be performed on all power and instrument transformers after installation and again after any removal and replacement of a unit.

a. Equipment Required

Same as indicated for the turns ratio test or a battery and a d'Arsonval Meter.

16. Protective Relay System Tests

All protective relays and each protective relaying scheme as a whole should be subjected to operational tests at least once per year. The test will vary depending upon the particular scheme and component relays, however, the test should in all cases be of the type where actual abnormal operating conditions are simulated and the proper operation of all components are checked.

Multi-phase current and potential sources should be used where applicable, rather than attempting to test multi-phase devices with single phase sources.

Whenever possible, an oscillograph or other type of multi-input events recorder should be used for timing of the various components.

Particular instruction books should be referred to for specific test values, settings and other pertinent data.

a. Equipment Required

(1) Test Set as manufactured by Multi Amp Corporation or equal.

(2) Phase Shifter as manufactured by States Co. (Div. of Multi Amp Corporation) or equal.

(3) Auxiliary current and instrument transformers.

(4) Portable Meters.

17. Meter Calibration Tests

Indicating instruments should be tested by comparison with a portable instrument which is connected into the same circuit as the instrument being tested. Test switches are usually provided for this purpose on the front of the panel.

Energy meter testing is usually performed in the utilities meter shop and thus is not provided for at the substation site.

a. Equipment Required

Many methods of test are employed, each of which requires different equipment. Typically, one of the following is used:

(1) Portable Standard Loads

(2) Portable Rotating Standard

(3) Single Phase, Series Tests

(4) Element Balance Tests

(5) When calibrating meters, the following loads should be used:

10% load at 1.0 pf.

100% load at 0.5 pf.

100% load at 1.0 pf.

18. Capacitance Test

The capacitance coupling capacitors, the condenser section of bushings and other similar capacitive devices should be verified at time of installation. Periodic measurements are usually not made unless a specific reason is incurred.

a. Equipment Required

Schering Bridge or equivalent.

19. Pressure Test

All high pressure receivers and associated piping should be subjected to a pressure test at time of installation and any time thereafter when the system has been subjected to repairs, extensions, alterations, etc.

The pressure utilized for this test should be approximately 150% of normal pressure in systems that operate below 100 psi. In higher pressure systems, the normal operating pressure is usually sufficient. In either case, the system should be sealed and the

pressure monitored over at least 8 hours (overnight is preferable). The only pressure variations should be those caused by change in temperature.

a. Equipment Required

The pressure gauge required is normally an integral part of the system being tested.

20. Ground Grid Resistance Measurement

As noted in Chapter XVII - Inspections, the ground grid resistance should be measured periodically to verify that significant changes have not occurred due to changes in ground water levels or other similar natural phenomenon. The value obtained should be compared with previously measured values or with design criteria values in the case of a new installation.

a. Equipment Required

Three probe type measuring device similar to Vibroground equipment as manufactured by Associated Research, Inc. or James G. Biddle Company.

TABLE XVIII-1

ACCEPTANCE TEST REQUIREMENTS

ITEM TO BE TESTED ↓ / REQUIRED TESTS →	INSULATION RESISTANCE TEST	POWER FACTOR TEST	DC HYPOT TEST	DIELECTRIC ABSORPTION TEST	AC OVER-POTENTIAL TEST	WINDING RESISTANCE MEASUREMENT	INSULATING OIL DIELECTRIC STRENGTH	INSULATING OIL POWER FACTOR TEST	TIMING TEST	* SERIES OVERCURRENT TEST	TURNS RATIO TEST	POLARITY TEST	CAPACITANCE TEST	PRESSURE TEST OF PIPING AND RECEIVERS	GRID RESISTANCE	VISUAL INSPECTION
TRANSFORMER, CONSERVATOR TYPE	X	X		X		X	X	X			X	X				X
TRANSFORMER, INERT GAS CUSHION TYPE	X	X		X		X	X	X			X	X				X
LOAD TAP CHANGER MECHANISM		X					X	X								X
REGULATORS		X		X		X	X	X								X
OIL CIRCUIT BREAKERS		X					X		X							X
AIR CIRCUIT BREAKERS		X			X					X						X
VACUUM CIRCUIT BREAKERS		X							X							X
SF_6 CIRCUIT BREAKERS		X							X					X		X
AIR BLAST CIRCUIT BREAKERS		X							X					X		X
PT'S	X	X									X	X				X
CT'S	X	X									X	X				X
CCPD'S		X											X			X
SURGE ARRESTERS		X														X
CABLE, 600 VOLT	X			X												X
CABLE, 5 KV AND ABOVE	X	X	X	X												X
DISCONNECTS AND AIR BREAK SWITCHES		X														X
VACUUM SWITCHES		X	X						X							X
CIRCUIT SWITCHERS		X							X							X
CAPACITORS													X			X
METALCLAD SWITCHGEAR	X	X	X	X	X											X
PROTECTIVE RELAYS	X				X											X
METERING EQUIPMENT	X															X
SUBSTATION GROUND GRID															X	X
TEST PROCEDURE OR DETAILS OUTLINED IN PARAGRAPH	01	02	03	04	05	08	09	09	012	015	016	017	020	021	022	

TABLE XVIII-2

PERIODIC TEST REQUIREMENTS

ITEM TO BE TESTED ↓ / REQUIRED TEST →	INSULATION RESISTANCE TEST	POWER FACTOR TEST	DC HYPOT TEST	DIELECTRIC ABSORPTION TEST	AC OVER-POTENTIAL TEST	CONTACT RESISTANCE TEST	CALIBRATION TEST	INSULATING OIL NEUTRALIZATION NUMBER	INSULATING OIL INTERFACIAL TENSION	INSULATING OIL DIELECTRIC STRENGTH	INSULATING OIL COLOR TEST	INSULATING OIL VISUAL EXAMINATION	INSULATING OIL POWER FACTOR TEST	INSULATING OIL COMBUSTIBLE GAS ANALYSIS	SF_6 GAS ANALYSIS	TIMING TEST	MOTION ANALYZER TEST	SERIES OVERCURRENT TEST	TURNS RATIO TEST	CAPACITANCE TEST	GRID RESISTANCE	VISUAL INSPECTION
TRANSFORMER, CONSERVATOR TYPE	12	12						12	12	12	12	6	12	6					24			2
TRANSFORMER, INERT GAS CUSHION TYPE	12	12						12	12	12	12	6	12	6					24			2
LOAD TAP CHANGER MECHANISM		12						12	12	12	12	6	12									2
REGULATORS	12	12						12	12	12	12	6	12									2
OIL CIRCUIT BREAKERS		12				12		12	12	12	12	6	12			12	12					2
AIR CIRCUIT BREAKERS		12			24											12		12				2
VACUUM CIRCUIT BREAKERS		12														12						2
SF_6 CIRCUIT BREAKERS		12				12									12	12						2
AIR BLAST CIRCUIT BREAKERS		12				12										12						2
PT'S		12																				2
CT'S		12																				2
CCPD'S		12																		12		2
SURGE ARRESTERS		12																				2
CABLE, 600 VOLT																						2
CABLE, 5 KV AND ABOVE		12	12	12																		2
DISCONNECTS AND AIR BREAK SWITCHES		12				12																2
VACUUM SWITCHES		12	12			12																2
CIRCUIT SWITCHERS		12				12																2
CAPACITORS																				12		2
METALCLAD SWITCHGEAR	12	12	12		24																	1
PROTECTIVE RELAYS					24		12															1
METERING EQUIPMENT							12															1
SUBSTATION GROUND GRID																						1
TEST PROCEDURE OR DETAILS OUTLINED IN PARAGRAPH	01	02	03	04	05	06	08	09	09	09	010	010	010	011	012	013	014	015	016	020	022	

NOTES

1 THE NUMBER IN THE BOX INDICATES THE AMOUNT OF TIME IN CALENDAR MONTHS BETWEEN PERIODIC TESTS

CHAPTER XIX - MAINTENANCE

A. PURPOSE

The purpose of this section is to recommend procedures to develop and maintain an effective and corrective maintenance program for substation equipment. This includes both scheduled periodic maintenance as well as that required to correct specific problems. Recommendations as to the frequency for the periodic maintenance is also included.

B. GENERAL

Periodic maintenance procedures, more commonly referred to as preventive maintenance, are developed and instituted in an attempt to minimize unscheduled service interruptions. The degree of success is generally reflected by the quality of the maintenance program.

Periodic maintenance procedures are generally performed in conjunction with normally scheduled inspection and testing programs which are outlined in Chapters XVII and XVIII, INSPECTION and TESTS, respectively.

The details for the required periodic maintenance vary considerably depending upon the details of the specific equipment. The maintenance program borrowers develop for substations must be tailored to meet the requirements of both the site and the equipment at that site.

Manufacturers instruction books should be referred to for all equipment requirements.

1. Records

A records system, as outlined in Chapter XVII - Inspection should be maintained. In addition to the details contained therein, these records should include at least the following information:

a. A description or outline of the specific maintenance program.

b. The date when maintenance was performed and the date when it should again be performed.

c. Any requirements for special follow-up work.

2. Safety

Certain maintenance procedures may be performed with the equipment in service while other procedures require that the equipment be de-energized. Scheduled outages quite frequently afford the best opportunity for maintenance and thus should be used to the greatest avail. When it is necessary to remove a piece of equipment from service without de-energizing the total substation, minimum safety clearances as specified in Chapter XVII, must be maintained. Temporary barriers should be installed to isolate the equipment being worked on from adjacent energized equipment.

C. PERIODIC MAINTENANCE

Periodic maintenance programs must incorporate manufacturers recommendations, both with respect to details of the work and with respect to its frequency. Typical items of work and their frequencies are indicated in Table XIX-1.

1. Specific Requirements

In addition to those items of maintenance listed in Table XIX-1, the following should be performed at the time monthly visual inspections are made.

a. Eliminate any low spots that have developed in the substation yard.

b. Remove trash from area.

c. Replace all burned out lamps.

d. Remove bird nests and other items from vicinity of energized parts.

e. Clean and refinish defects in paint and galvanizing.

f. Removal of vegetation should be made at periodic intervals. If chemical application for removal of vegetation is required, consult the local

farm extension agency or governing authority for proper methods and chemicals.

If areas requiring work are near energized parts, this must not be performed without de-energizing the area.

2. Painting

Periodically, depending upon the geographic location, local environment, etc., equipment, fences and structures must be repainted. The following should be considered as minimum requirements:

a. Equipment and Other Painted Items

(1) All loose paint, blisters, and scale must be thoroughly removed. Where the condition of the finish is poor the paint should be removed entirely. Wire brushing, sandpapering, or scraping is desirable where only partial surface cleaning is necessary. Paint removers will soften and aid in removal. However, the paint remover must be neutralized before attempting to paint. For removal of oil and dirt, weak solvents such as mineral spirits, other petroleum thinners, or turpentine substitutes should be used.

(2) Painting should be done as soon as possible after cleaning. All bare metal should be covered with a primer. Where only chalking has occurred, one finish coat is sufficient. Primer and finish paints may be obtained from most equipment manufacturers and sometimes from local sources. A zinc chromate alkyd resin primer followed by an alkyd base paint is a suitable air-dry combination for exterior surfaces. The primer coat should be allowed to air-dry thoroughly and should be followed by two finish coats with sufficient time allowed between coats for drying.

b. Galvanized Structures and Fences

(1) The protective coating produced by the galvanizing process is normally a long-lived coating; however, the coating will eventually fail and rust will appear. It has been estimated that Class II hot dipped galvanizing on chain link fences in rural locations will normally furnish adequate protection for many years. The life of the coating on structural steel used in substations should generally be longer than 12 years except possibly for upper flat surfaces of horizontal members. Any failure of the coating will usually occur in spots rather than over an entire surface. The following procedure is recommended:

(2) Clean the surface with a wire brush or by other mechanical means to remove rust and dirt. If the surface is contaminated with grease or oil a solvent should be used to remove those contaminants. Mineral spirits or a weak solution of trisodium phosphate can be used as the solvent. A solution of one ounce of trisodium phosphate to one gallon of warm water is suggested for cleaning the metal. In the event that it is uneconomical or impractical to remove all rust, a reasonably satisfactory job can be obtained by deactivating the rust through chemical treatment. A weak solution of phosphoric acid is suggested for deactivating rust. The use of proper skin and eye protection is recommended.

(3) Apply a priming coat to the clear dry surface using a good zinc dust - zinc oxide paint. Allow ample time for the paint to dry before applying the finish coats.

(4) Two finish coats should be applied using the same type paint as was used for priming. Ample drying time should be allowed between finish coats. One finish coat only is needed for areas on which the galvanized coating remains intact. The color of the paint is grey but colors in oil may be

added to the finish coats to obtain other shades. Other paints normally used as final coats for metal (such as aluminum paint) may be used as the final coat in place of the zinc dust - zinc oxide paint.

It is recommended that painting of outdoor metal work be done only when the temperature is above 7.2°C (45°F) and when the relative humidity is below 80 percent.

The durability of a paint coating depends on thickness, cohesion and continuity. Generally 5 mils (.005 inch) is an adequate thickness. The thickness should be uniform and paint should not be easily scraped off the metal. Welds, edges and other hard-to-coat areas should be given particular attention.

D. UNSCHEDULED MAINTENANCE

Any abnormal conditions that are noted during any periodic inspection may need to be corrected as soon as possible, depending upon the severity. In many cases, the equipment must be removed from service prior to commencement of work. Abnormal conditions and corrective measures include:

1. Loose Or Corroded Connections - Tighten or replace, depending upon condition.

2. Contaminated Bushings - Clean all exposed surfaces, including casing, porcelain and oil gages.

3. Leaking Or Damaged Bushings - Repair or replace.

4. Deteriorated Insulating Oil - Recondition or reclaim depending upon situation (See IEEE No. 64 and Chapter XVIII of this Guide).

5. Low Pressure Of Inert Gas Cushion - Replace gas cylinder if required and check gas system for leaks, etc.

6. Pressure Relief Device Operated - Reset device and determine cause for operation.

7. Oil Leaks - Repair, tighten, weld, etc., as required.

8. Sludge Or Carbon Deposits In Tank - Remove deposits and clean. Determine cause for deposit, i.e., deteriorated oil, internal faults, etc.

9. Damaged Items

In addition to the items contained in the previous paragraphs, it can be anticipated that certain abnormal items will be noted that can only be remedied by replacement of the damaged item. These include:

a. Damaged potheads, high voltage cable, damaged porcelain (bushings, surge arresters, insulators, etc.) and other items subject to high electric stress.

b. Failing capacitors as evidenced by insulating fluid leaks around bushings or bases, bulging tanks, blown fuses on individual units or groups of units, etc.

NOTE: It may be necessary to de-magnetize the core in current transformers if they have been subjected to very high magnitude currents that have resulted in saturating the core. Modern high-accuracy current transformers show relatively little change in accuracy due to magnetization. However, should a current transformer core become magnetized by surges due to opening the primary circuit under heavy load or any other means, it may be conveniently demagnetized by several methods.

One reliable method requires connection of a variable ac source to the secondary of the current transformer to be demagnitized after the power circuit has been de-energized. During the test the primary of the current transformer is left open-circuited. The secondary winding current is slowly increased from zero to five amperes, and then steadily reduced to zero again before disconnecting the test source from the secondary winding.

It is important to note that when demagnetizing high impedance type current transformers, it may require up to 450 volts across the secondary terminals. Appropriate caution is required.

TABLE XIX-1

RECOMMENDATIONS FOR PERIODIC MAINTENANCE

EQUIPMENT \ MAINTENANCE PROCEDURE	Clean Exposed Porcelain	Clean, Lubricate & Adjust Mech.	Clean or Replace and Align Contacts	Tighten Connections	Major Overhaul	Clean Burnish Contacts	Lubricate Aux. Motors	Replace Dehydra- tor in Breather	Change Oil in Gear Boxes	Check Liquid Levels
TRANSFORMERS, INERT GAS CUSHIONED	12			12			6			
REGULATORS	12			12						
OIL CIRCUIT BREAKERS	12	12		12	*					
AIR CIRCUIT BREAKERS	12	12		12	*					
VACUUM CIRCUIT BREAKERS	12			12	*					
SF_6 CIRCUIT BREAKERS	12			12	*					
AIR BLAST CIRCUIT BREAKERS	12			12	*					
PT'S	12			12						
CT'S	12			12						
CCPD'S	12			12						
SURGE ARRESTERS	12			12						
DISCONNECTS & AIR BREAK SWITCHES	12	12	12	12			6		24	
VACUUM SWITCHES	12		12	12						
CIRCUIT SWITCHES	12		12	12						
CAPACITORS	12			12						
METAL CLAD SWITCHGEAR		12		12						
RELAYS				12		12				
TRANSFORMER TAP CHANGER MECH.					*					
TRANSFORMER, CONSERVATOR TYPE	12			12				6		
STATION BATTERY										2

NUMBER INDICATES RECOMMENDED INTERVAL OF TIME (IN CALENDAR MONTHS) BETWEEN MAINTENANCE TIMES

ASTERISK (*) INDICATES THAT THE REQUIREMENT FOR MAINTENANCE IS A FUNCTION OF THE NUMBER AND/OR TYPE OF OPERATIONS

CHAPTER XX - UPRATING AND EXPANDING EXISTING SUBSTATIONS

A. INTRODUCTION

This chapter deals with uprating and expanding existing substations. It discusses the applicability of the practices recommended in the guide as they relate to uprating and expansion plans and the feasibility of uprating or expanding as compared with construction of new facilities. Uprating, in this chapter is defined as increasing the rating of the existing substation systems and equipment. Expanding is defined as adding circuits and related equipment.

B. APPLICABILITY

All substation design and construction including uprating and expanding must be based on sound practices to ensure safe, reliable operation. While it may not always be practical in uprating to attain every desired recommended clearance and spacing, minimums where established in this bulletin or other applicable national or local standards must be met or exceeded.

C. FEASIBILITY

Cost is usually a primary factor when determining a course of action - construction of a new facility versus uprating and/or expanding an existing facility. Construction cost estimates should be prepared for the schemes under consideration. The plan with the most favorable cost benefit ratio should generally be chosen provided that such action is consistent with the near and long range system plan.

Substation uprating may be considered as an alternative where increased capacity is required and routine expansion is hindered due to lack of land area. During the initial planning of an uprating program it may become apparent, after discussions with manufacturers, that such a program is not cost effective. In this case, expansion or new construction is usually the most desirable course of action.

D. SUBSTATION UPRATING

In uprating substation equipment, the cooperation of the equipment manufacturer is usually required. Although an agent or

distributor for the equipment Vendor may be initially contacted, final determinations should be obtained from the manufacturer's headquarters engineering staff as to technical feasibility of the uprating, the cost of such work and where the work can be done, field or manufacturing plant.

When equipment uprating is being considered, only the capacity is increased. The voltage level remains the same. Normally the location of incoming or outgoing circuits remains the same although they may be reconductored for increased capacity.

1. Major Equipment Uprating

   a. Power Transformer

      In the initial phase of a planned substation uprating, the power transformer manufacturer should be furnished with complete nameplate data. Additionally, original purchase information, such as purchase order number and date should be supplied. This information will make it possible for the manufacturer to retrieve the original design calculations to determine the possible additional capacity.

      If the original design was conservative, some additional capacity may be possible. A loading history may be necessary to confirm this. If the unit is oil insulated, self-cooled, the addition of radiators and fans should provide added capacity. If the unit is fan-cooled, additional or larger fans or radiators may add to available capacity. Insulating oil pumping, or additional pumping, may be necessary to further increase the rating. In some cases, internal leads may require inspection, testing and even replacement.

      There are variations between manufactures but, in general, a 15-20 percent increase in MVA capacity may be possible.

   b. Oil Circuit Breaker

      Increasing the MVA capacity of a substation may necessitate increased circuit breaker ratings. Breakers may be inadequately rated for increased continuous and momentary currents and interrupting duty. Consequently, the fault and continuous current requirements of all associated breakers must be determined.

The existing oil circuit breakers may be adequate for the increased full load current but inadequate for the interrupting duty to be imposed.

The manufacturer of the breakers should be given complete nameplate and purchase data together with the ultimate full load current and asymmetrical fault current expected from the uprating program.

From this data the feasibility of the program can be determined as far as the breakers are concerned.

New contacts and bushings may possibly overcome any full load current deficiency. Replacement of interrupter units could safely handle the increased interrupting duty.

c. <u>Current Transformer (CT)</u>

Transformer and circuit breaker bushing current transformers should be evaluated for thermal rating under the uprate program by the equipment manufacturer when the apparatus is being assessed. If determined inadequate, replacement will be necessary. Next the ratio suitability must be determined. For example, a 3000/5 multi-ratio CT, being operated on the 1200/5 tap can be reconnected for 2000/5 service.

The same is true for other substation CTs.

d. <u>Wave Trap</u>

Since a wave trap or line trap is a current rated device it is undesirable to operate such equipment above the nameplate rating. In most cases of uprating, wave traps will require replacement.

e. <u>Coupling Capacitor Voltage Transformer (CCVT)</u>

A CCVT is a voltage rated device as is the associated line coupling tuner when the CCVT is equipped with carrier current assessories. Replacement will not be required for a capacity uprating program unless the addition of new metering or relaying exceed the loading limits of the device.

f. Voltage Transformer (VT)

A VT is in the same category as a CCVT relative to uprating.

g. Bus System

Two factors enter the uprating considerations regarding the substation bus system. These are: current carrying capacity of the conductors and connections; and fault current capability of the conductor support systems.

An increase in bus current is directly proportional to the increase in substation MW capacity. However, the increase in bus heating is proportional to the current square (I^2R). This heat increase must be considered. Additional heat may, by conduction, affect connected apparatus. Also, it becomes progressively more difficult to maintain good bolted joints, free from deterioration, as the temperature increases. For these reasons, good practice generally indicates rating the bus for a 30°C (54°F) rise over a 40°C (104°F) ambient under full load conditions. Under emergency conditions consideration can be given to a 25 percent maximum bus current increase. These loadings should however be limited to a couple days duration.

For heat rise computations, the necessary data and mathematical relations are available from conductor manufacturers and industry associations. An excellent publication of this nature, "Aluminum Electrical Conductor Handbook," is available from the Aluminum Association, 750 Third Avenue, NY 10017.

When the thermal considerations of the uprated bus have been calculated, it must be decided if the existing conductor should remain or be replaced. If strain bus, possibly only the drops need changing to a larger size. If the substation uprating is a measure to buy time prior to a more extensive program to serve load growth, possibly the bus need not be replaced.

The fault currents associated with a substation, in the case of rigid bus mounted with apparatus insulators on structures, cause stress in the insulators and

structures. With the added capacity and consequent increase of the fault current, it is necessary that these stresses be calculated to determine if insulators or structures are adequate. Methods of calculation are described in Chapters IV and VII.

The insulator cantilever strength will most likely be the weak element under the uprated condition. Several courses are open to remedy this situation. Insulators of increased cantilever strength can be installed on the center phase only. However, it may be necessary to change all insulators to higher strength depending on the calculated forces. Additional bus structures to reduce bus span length may be an answer, although probably a costly solution.

h. Disconnecting Switches

The increased current of the uprated substation will require that the disconnecting switches be examined for full load rating. This can be done from the substation records or the switch nameplates. The momentary current capability should also be checked. If either the full load or momentary currents are found inadequate, the original equipment manufacturer should be consulted. It may be possible to uprate the switches by additions or replacement of the current carrying parts and insulators. If this is not possible or the switch Vendor no longer manufactures this product, the units must be replaced.

i. Surge Arresters

In that the voltage level or substation BIL is not usually increased in the uprating program, the surge (lightning) arresters need not be changed. However, if the existing units are of old and outdated design, it is advisable to replace, in particular, those positioned for power transformer protection.

j. Raceway System

Essentially, the only changes in the raceway system would be provisions for additional transformer fan and oil pump circuits. If the system is underground and spare raceways or ducts have not been provided, new direct burial plastic conduits can be installed above or beside existing duct banks thus using the present routing.

k. Auxiliary Systems

In an uprating program the essential addition to the auxiliary systems will probably include new ac circuits for transformer fans and oil pumps. These circuits should be considered as critical or essential loads and assigned a 100 percent demand factor. It is doubtful that the auxiliary transformers will need increasing in size. Normally these are specified conservatively. In addition, operating history of the substation may indicate that the existing loads were assigned a demand factor in excess of the true factor. However, the auxiliary transformer capacity should be nevertheless checked for adequacy.

The most important equipment check to make of the ac system in an uprating program is the capacity of the automatic transfer switch. This switch may have to be replaced with a unit having a larger rating, both full load and momentary.

l. Relaying and Metering

Unless the relaying scheme is being changed concurrently with the substation uprating program the changes to existing relays will usually consist of revising the settings. Some current transformers may have to be reconnected or replaced for different ratios both for relaying and metering. Since there is usually no voltage change in an uprating program, potential transformers and other voltage devices generally can remain the same.

E. SUBSTATION EXPANSION

1. General

Substation expansion is the addition of transmission, subtransmission or distribution circuits to existing substations. These additional circuits may be required on the primary or secondary side. In some cases modifications to the switching scheme may be necessary or desirable. At the same time capacity may be increased with the installation of an additional transformer/s.

A planned expansion is also the time to consider the possibility of a different voltage level. For example, should the expansion of a 115 kV substation be designed

for future 230 kV. Phase-to-phase rigid bus spacing is nominally 2.13 meters (7 feet) and 3.35 meters (11 feet), respectively. Installing structures and bus work for a higher voltage spacing and clearance with operation at the present voltage may be warranted when the long range system plan indicates increasing the voltage at a later date. When the expansion goes to the higher voltage this portion could be coupled to the existing through a suitable transformer or completely divorced from the lower voltage installation, depending on system configuration.

If a higher voltage construction is decided for the expansion and the higher voltage is contemplated within the near term (less than 10 years), foundations should be designed and installed for the higher voltage equipment. The advantages of the monolithic pour over the modification of a smaller foundation at a later date far outweighs the higher cost.

Reasonable equipment dimensions and weights for the higher voltage equipment are readily available from equipment manufacturers. The trend is to smaller, not larger, equipment so this risk is reasonable.

2. <u>Site Work</u>

If the expansion land area was originally set aside for a lower voltage, it must be enlarged to accommodate the future higher voltage.

Additional soil data should be obtained in the expansion area. It would be an invalid assumption to take for granted that conditions in the existing site carried on to the expansion area.

Other criteria for site work are covered in Chapter VI.

3. <u>Grounding</u>

The soil samples obtained for foundation design in the expansion area should be compared, if possible, with the soil record of the existing area to determine if resistivity measurements are necessary. If this is not possible, measurements should be taken.

A reasonable estimate of ground fault current can be calculated for the proposed higher voltage. The grounding system should be designed for this higher voltage using the methods described in Chapter IX.

4. Raceway System

If the existing substation employs an underground duct system, this does not in itself mandate the expansion to this method.

As described in Chapter X, cable trench has certain advantages over ducts. A large handhole can be designed to interface the existing ducts to a trench and the advantages of trench used throughout the expansion area. If the expansion area is later separated from the existing area, the handhole becomes an ideal point of electrical separation.

When the higher voltage level is built, the trench can be paralleled with the other trench for the increased cable requirements with segregation usually occurring at this level.

5. Control House

Unless substation expansion was planned in the original design and the control house sized accordingly, it will probably require enlarging. The enlarging should be designed with the higher, future voltage in mind.

6. Equipment

a. Bus System

A conservative estimate of expected fault currents at the higher voltage level should be made and the bus BIL established along with ground clearances to personnel, roads and fencing. Following the methods outlined in other chapters the bus and insulators should be designed at this level taking into account contemplated full load bus current.

b. Transformers and Circuit Breakers

The selection of transformers and circuit breakers together with their associated isolating switches is detailed in other chapters of this guide. This equipment should be specified for the operating voltage. Foundations and switch structures should be designed for the higher, future voltage. When the higher voltage becomes a reality, cutover will be a more orderly, less time consuming project. Disconnecting switches should be specified with the phase spacing of the higher level.

c. Carrier Equipment, Surge Arresters and Voltage Devices

This equipment must be specified at the operating voltage. However, foundations and supporting structures can and should be designed for the higher voltage for the reasons set forth previously.

d. Auxiliary Systems

Several equipment items must be checked and possibly revised or increased in capacity in the auxiliary systems to successfully expand an existing substation. These include:

1. Auxiliary transformer capacity

2. Throwover switch ratings, full load and momentary

3. Low voltage ac and dc panel circuit capacity and adequacy of mains

4. Low voltage switchgear circuit capacity

5. Battery and charger capacity

Redesign or modification of the auxiliary system of the expanded substation is accomplished by summing existing loads with the expansion loads and proceeding as outlined in Chapter XIV for a new installation.

A review of the operating history of the ac system may reveal that the originally assigned demand factors were overly conservative and the existing capacity may be adequate for the substation expansion.

The same could be true regarding the throwover switch. In the interest of reliability, any deficiency, however slight, indicates replacement of this switch.

Well designed ac and dc systems should have provided ample spare panel circuits and adequate mains. This may not have been done because no expansion was ever considered possible at the particular installation under consideration. A new panel can be tied directly to the existing panel by doubling the main lugs of the existing unit. The new panel should be located close to the existing and full ampere capacity cable installed.

Low voltage switchgear falls into the same category as the panels mentioned before. Additions can be made in the same manner using individual fused switches or circuit breakers.

The dc battery and charger, if not originally specified for equipment additions and/or if found inadequate, should be replaced for the substation expansion.

e. Relaying, Metering and Control

If the same relaying scheme as existing is applied to the substation expansion the only requirement is the addition of relay panels for the expansion together with associated control panels. In a situation of this nature the metering scheme would undoubtedly remain the same with equipment duplicating the existing equipment.

The different loading conditions of the substation with the expansion may require resetting of the relays of the existing portion.

The reason for the expansion program may dictate more complex, sophisticated protective relaying, both for the existing and the expanded substation. A situation such as this is practically identical to a completely new·design and should be treated accordingly.

F. PLANNING FOR UPRATING OR EXPANSION

All programs involving substation construction require planning. This is especially true of a program of uprating or expansion.

A CPM or similar method is recommended. Detailed activities of engineering, material specification, procurement, manufacturing and delivery times together with itemized construction activities should be included. Required service outages should be planned to cause the least revenue loss and customer inconvenience. Adequate time should be factored into the program to account for contingent delays that can and will occur. The program should provide for informing customers of forthcoming service outages so they can plan their activities around the outages.

Once the program or plan is developed it should be assigned to a qualified person to monitor the actual activities, both office and field.

The program will probably require revision as time passes, but with a detailed plan, future problem areas can be detected and appropriate action taken before they become crisis areas.

G. COMPARISONS - NEW VS UPRATING OR EXPANSION

Successful substation uprating will require a high degree of technical cooperation between the Borrower, his engineer and the manufacturers' staffs.

If uprating is just a "stop-gap" measure to favor a future program, the equipment manufacturer should be requested to provide a reasonable life estimate of the uprated equipment. This will assist in the priority assignment of the future program.

These comments apply largely to power transformers and if history of operation shows a minimum of operation above rated temperature, this life estimate, estimate, can be quite reassuring.

New substation construction obviously causes the least disturbance, electrically, to the customers and the system. In the case of a small installation, expansion can consist of duplicating the existing installation and making a "hot" cutover or otherwise placing the new section in service with minimum outage. In this case, if transformers are being paralleled, other chapters in this guide should be consulted for guidelines.

An expansion to existing facilities is on a par with uprating as to disturbance but with good planning and management of all phases of the program this can be kept to a minimum.

H. SUBSTATION UPGRADING

Substation upgrading by itself is difficult to justify due to the extent and cost of the modifications normally required. However, when coupled with concurrent substation expansion, upgrading can often become the best choice compared with construction of a completely new facility.

Substation modifications or upgrading are warranted when conditions affecting safety or security are evident. Substations, particularly those of early vintage, may not meet current minimum recommended requirements for insulation, electrical clearances, or structural integrity. In these instances a thorough examination should be made to determine the most efficient and economical method to improve the situation.

Constuction of a new installation with ample provisions for future expansion may be the best choice, particularly if extensive modifications are required.

Is should be noted that because a standards group has lowered permissible operating temperatures or made other standards changes to certain equipment or materials, if no trouble has been experience and maintenance is properly scheduled on existing equipment installed under the older standards, this equipment need not be arbitrarily replaced.

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International System of Units

In December 1975, Congress passed the "Metric Conversion Act of 1975." This Act declares it to be the policy of the United States to plan and coordinate the use of the Metric system.

The metric system, designated as the International System of Units (SI), is presently used by most countries of the world. The system is a modern version of the meter, kilogram, second, ampere (MKSA) system which has been in use for years in various parts of the world.

To promote greater familiarization of the metric system in anticipation of the U.S. converting to the system, REA is including metric units in its publications. This bulletin has, therefore, been prepared with the International System of Units (SI) obtained from ANSI Z 210-1976 - Metric Practice. Approximately equivalent Customary Units are also included to permit ease in reading and usage, and to provide a comparison between the two systems.

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